Peterhead CCS Project

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Executive Summary

This report, Well Completion Concept Select Report, includes the rationale for selecting the preferred completion from the range of options available considering the lifecycle of a well in the Peterhead Goldeneye Carbon Capture and Storage (CCS) project.

The report considers the inflow performance (injectivity and matrix/fracturing conditions), the vertical flow characteristics (pressure and temperature calculations) in relation to the phase behaviour of the Carbon Dioxide (CO_2).

Different completion concepts are analysed for the Goldeneye conditions and lifecycle (installation/injection/abandonment) and a recommendation is done for the completion type to mature in the define phase of the project (FEED). The Completion Concept for the upper completion presented in this report is similar to the proposed for the Longannet project. Changes related to flow rates, pressures and CO_2 composition were included in the analysis.

The current upper completion was designed for hydrocarbon production. Analyses have shown that injecting dense phase CO_2 into a depleted reservoir has the risk of producing low temperatures in the injection tubing. These low temperatures cause problems with the materials and fluids in the wells. In order to avoid this, small injection tubing is being installed. This will introduce additional friction and will maintain the injection column in dense phase from the well head to the sand face.

Limitations of the different well components were investigated for the expected well conditions under CO_2 injection. The Christmas tree and the tubing hanger will be replaced in the workover with units having a lower minimum temperature. All completion equipment (i.e. attached to the tubing string) will have 13Cr or s13Cr equivalent (or superior) metallurgy and will have working pressures in excess of the expected final well pressures.

Based on the hydrocarbon production and the reservoir characteristics it is expected to have a good initial injectivity in the Captain D. Filters will be installed on the platform to avoid particulates and hence reduction of injectivity by plugging/erosion of the lower completion and formation. Batch hydrate inhibitor is planned before well start-ups during the initial stage of injection to avoid hydrate formation in the well. It is expected that matrix type of injection will occur at low reservoir pressures changing to fracturing conditions with increase in reservoir, being the main uncertainty the thermal effect on the rock.

The lower completion installed in the Goldeneye wells (screen and gravel pack) is considered fit for purpose for CO_2 injection. Filtration of the CO_2 stream will reduce the risk of plugging and erosion of the lower completion.

The installation of small bore tubing in the wells limits the operating envelope of each well. In order to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well will be completed with a different tubing size/configuration tailored to a specific rate range. The wells will then have overlapping operating envelopes and any rates specified in the integrated basis-for-design will then be achievable through the choice of a specific combination of wells.

In the completions, there will be permanent temperature and pressure monitoring gauges. There will also be a distributed temperature sensing system - a fibre optic system providing temperature data at specified intervals in the well, and distributed acoustic sending (DAS).

Three wells are planned to be converted as injector wells. GYA03 is planned to be a monitoring well. The range of injection from the minimum to the maximum of the capture plant at the predicted reservoir pressure evolution can theoretically be achieved with only two wells. In case of unforeseen problems in a particular injector well, it is proposed to complete an additional or back-up well as a

CO_2 injector to the number of wells required to cover the injection range. As such, at least three wells are required to be completed as injectors. The well(s) not converted for CO_2 injection will also need to be considered for the Peterhead project. Options included are to complete as an injector/monitor or to abandon the well.

1 Introduction

General injection requirements

The Goldeneye platform features five suspended gas production wells, with an additional three spare slots for potential future wells. Suspension plugs were installed in the existing producing wells after the Cessation of Production (CoP) declaration.

The injector wells should be able to inject 10 million tonnes with a maximum rate of 138.3 tonnes/h. Turn down of the surface facilities are estimated at 89.9 tonnes/h (65% of the design rate). The CO_2 to be injected is almost pure (+99.9%) and it is arriving to the platform dehydrated (~20ppm weight of H_20) at temperatures similar to the seabed temperature and pressures above the critical point.

The reservoir will be depleted at the start of injection. The reservoir pressure will increase with CO_2 injection; at the end the 10 million tonnes of injection, the reservoir pressure will be close to hydrostatic conditions.

There is an aquifer attached to the formation. Completion design should consider the presence of water and hydrocarbons (not only CO_2). Water is present in currently present at the formation level. The CO_2 in presence of water is highly corrosive in carbon steel. Hydrocarbons are also present in the current wells.

Injectivity

The initial CO_2 injectivity is expected to be excellent (~200-400 psia [~13.8-27.6bara] above the reservoir pressure) for the expected injection rates per well required for the project. This high injectivity is based on the rock properties of the Captain D (storage formation) and the productivity of the hydrocarbon production phase.

The expected CO_2 injectivity under matrix conditions can be estimated from the hydrocarbon productivity by considering the differences in (Pressure-Volume-Temperature) PVT between the hydrocarbon and the CO_2. The impact of the PVT correction is small in the injectivity as the high viscosity of the CO_2 is compensated by the low expansion factor of the CO_2 with respect to the hydrocarbon gas.

The risk of not being able to inject the desired amount of CO_2 can be reduced by some proactive measures such as filtration of the CO_2 stream (5 micron) and hydrate inhibition (bath displacement of methanol between the Xmas tree and the Sub Surface Safety Valve (SSSV) before opening the well). There are other mechanisms, which are considered of very low risk to CO_2 injectivity such as: Joule Thomson cooling, Halite precipitation, and organic deposits like wax and asphaltenes.

Stress regime calculations in combination with the expected injection pressures indicate that the initial phase of injection (for low reservoir pressure) will be under matrix injection. However, the late phase of injection (as the reservoir pressure increases) is uncertain in terms of injection condition (matrix or fracturing conditions). The main uncertainty in the calculations is the reduction in minimum stress caused by the temperature contrast between the reservoir temperature and the bottom hole injection temperature which effectively reduce the minimum stress of the formation.

Injection under fracturing conditions will propagate fractures in the Captain formation. These fractures in the reservoir are not detrimental to the containment capacity of the primary reservoir seal (Rodby/Hidra formations).

Vertical lift performance

The CO_2 stream arrival temperature to the platform would be between 2.3°C to 10.1°C depending mainly on seabed temperature and some expansion/cooling in the riser.

Analyses have shown that injecting cold liquid CO_2 into a depleted reservoir has the risk of producing low temperatures in the injection tubing due to the Joule-Thomson (JT) expansion.

CO_2 expansion properties can be managed by a small diameter tubing resulting in temperatures compatible with the materials in the existing wells. This will introduce enough friction and will maintain the injection column in dense phase from the wellhead to the sand face. With appropriate size in the tubing the wellhead pressure can be increased to the extent that it lies above the saturation line. As such, the minimum wellhead pressure in the well is determined by the requirement of operating the well in single phase. This will create a minimum rate limitation in each well.

The maximum CO_2 pressure available (~120bara) will dictate the maximum injection rate per well for a given tubing size.

Tubing sizes can be designed to accommodate variable flow rates from the platform by using multiple wells.

Low temperatures for a short period of time can be encountered during transient operations (start up and shut down). A procedure for testing the SSSV needs to be validated in the next phase of the project.

For the Carbon Capture Plant (CCP) rates in the project, the expected bottomhole temperature is estimated between 23°C to 35 °C.

Loss of control in a CO_2 well can generate very low temperatures in the top of the well. In a CO_2 well; with the rapid expansion of the CO_2, correspondingly rapid cooling will occur. The top of the well (wellhead, Xmas tree and tubing above the SSSV) will require special considerations due to the potential low temperatures.

Injecting into existing wells

The five existing wells were evaluated to be used as CO_2 injection without any modification. However, due to potential integrity issues and CO_2 phase behaviour management it is not possible to use the wells without any modification. A rig is required to carry out a workover of the upper completion by installing small tubing in order to manage the CO_2 expansion.

Due to the material compatibility in the lower completion it is recommended to control the Oxygen to acceptable levels. This has been calculated at 1ppm Oxygen in the CO_2 stream.

As the lower completion (screen and gravel), filtration of the CO_2 stream will reduce the risk of plugging and erosion of the screens.

The lower completion installed in the Goldeneye wells (screen and gravel pack) is considered fit for purpose for CO_2 injection.

There is not a requirement to perform side-tracks if pro-active control measurements are followed (filtration and oxygen control) for the lower completion.

Conceptual completion selection

CO_2 phase behaviour management can be achieved by extra pressure drop in the well. Options include the installation of a small diameter tubing creating back pressure by friction loss or a pressure drop in a device (downhole choke).

The initial installation of the single tapered completion option is the simplest and most robust. The other evaluated systems - insert string, dual completion, concentric completion and downhole choke - present extra design /operation challenges and additional cost in comparison to the selected single tapered completion. As such, the proposal for the upper completion is to use single wells with slim tubing sizes.

Well construction elements

Limitations of the different well components have been investigated for the expected well conditions under CO_2 injection. The change of use of Goldeneye wells from hydrocarbon production to CO_2 injection has been checked against the existing well design in the following areas: materials (metallurgy and elastomers), casing design, cement and pressure management.

Re-completion of the wells will incorporate changing out of the 7" [178mm] tubing to a smaller size. It is proposed to standardise the top (from surface Xmas tree down to the SSSV) and the bottom (tail pipe up to the Permanent Downhole Gauge (PDG) mandrel) of the upper completion for the CO_2 injection.

Distributed Temperature System (DTS) will be installed in the wells for monitoring purposes.

All completion equipment (i.e. attached to the tubing string) will have 13 percent Chrome metallurgy (13Cr) or super 13 percent Chrome metallurgy (S13Cr) equivalent metallurgy and will have working pressures in excess of the expected final well pressures.

The Xmas tree and the tubing hanger will be replaced in the workover with units having a lower minimum temperature rating than the currently installed.

For normal well operating conditions (injection and transient conditions) the wellhead system is compatible with the expected low temperatures. Detailed thermal simulations of the wellhead/Xmas tree system under uncontrolled CO_2 leaks will be done in the next phase to evaluate the extension of the low temperature during leak scenarios for validating the suitability of the wellhead system.

Number of wells

The number of required injector wells depends mainly on the injection estimates (reservoir pressure and injectivity), capture plant rates, CO_2 management, monitoring requirements and life cycle risk management.

The well(s) not converted for CO_2 injection will also need to be considered for the Peterhead project. Options included are to complete as an injector/monitor or to abandon the well.

The installation of small bore tubing in the wells limits the operating envelope of each well. In order to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well will be completed with a different tubing size/configuration tailored to a specific rate range. The wells will then have overlapping operating envelopes and any rates specified in the integrated consortium basis-for-design will then be achievable through the choice of a specific combination of wells.

The current plan is to recomplete the five existing production wells by means of a workover – replacing upper completion. Whilst purely for CO_2 injection, based on the latest scheduled volumes of captured CO_2 from the Peterhead power plant, there is a requirement for three injection wells only. There is an additional requirement for one monitoring well (GYA03). There is a choice whether the fifth well should be recompeted for injection or abandoned..

Drilling of new wells

New wells are not currently considered for the project. Drilling new wells to avoid the limitations of eliminating the minimum rate dictated by the CO_2 phase behavior is not justified.

Drilling new wells might only be justified in case of leak cases where the wellhead system needs to be replaced based on consequences arising from a failure case. Experience in CO_2 EOR and other CCS projects under leak scenario indicated not to be an issue. Detailed thermal simulations of the wellhead/Xmas tree system will be done in the FEED phase to evaluate the suitability of the system under Goldeneye conditions.

As a consequence, in the case of drilling new wells, they should be able to take low temperatures (sub-zero) in the top part of the well (~2600ft [792.5m] under injection conditions and even lower temperatures for leak scenarios in the very top of the well).

2 Completion requirements

2.1 Introduction

The Goldeneye platform features five suspended gas production wells, with an additional three spare slots for potential future wells.

The five existing wells in the Goldeneye platform initially drilled and completed to produce hydrocarbons form the Captain sands, Table 2-1 . The abbreviated well names are used in this document. Well DTI 14/29a-A4Z (GYA02S1) is the sidetrack of DTI 14/29a-A4 (GYA02).

Table 2-1: Existing hydrocarbon producer wells in Goldeneye platform

Full well name	Abbreviated well name	Spudded (batch operations)
DTI 14/29a-A3	GYA01	8/12/2003
DTI 14/29a-A4Z	GYA02S1	13/12/2003
DTI 14/29a-A4	GYA02	13/12/2003
DTI 14/29a-A5	GYA03	19/12/2003
DTI 14/29a-A1	GYA04	5/12/2003
DTI 14/29a-A2	GYA05	2/12/2003

The field was granted CoP (Cessation of Production) from DECC (Department of Energy and Climate Change) in 2011. There are therefore no plans to produce the wells in the future.

These wells can be used for CO_2 injectors or as monitor wells. Suspension plugs were installed in the existing producing wells after the CoP declaration.

2.2 General completion considerations

The main functional requirements for the wells in the Peterhead Goldeneye CCS project are:

Hydraulic Requirements

- Management of the CO_2 properties (Joule Thomson, JT expansion) and the resultant temperatures in the existing platform wells.
- Flexible injection. The injector wells need to be able to cope with a range of CO_2 arrival rates within the limits of the capture plant and surface equipment. Facilities and their modus operandi should be operated to have minimum impact in the wells.
- CO_2 will be injected in a single phase with wellhead pressure kept above the saturation line.

Well Integrity

- Avoid any leak path through the well.
- All well completion materials should be compatible with the injected fluid and expected pressures and temperatures.
- Completion design should consider the presence of CO_2, water and hydrocarbon. The proportion will change depending on the well position and during the life of the project.
- Expected remaining well life after start of injection: minimum 15years.

Well Modifications

- A mobile jack-up rig will be required for Goldeneye platform due to the water depth.
- Minimise complexity of any well work. Uncomplicated well design.

Operational aspects

- Normally unattended platform.
- Maintain injectivity during the life cycle of the well.
- Optimise well life cycle cost..

Well Monitoring

- Able to monitor wells/reservoir. Facilitate intervention.
- In-well monitoring to be installed in the wells: Permanent Downhole Gauges (PDG) and Distributed Temperature Sensing (DTS) (Distributed Acoustic Sensing (DAS) being considered).

Life Cycle Cost

- Regulatory responsibility for the five existing wells will transfer from the production license to a new storage licence. As such, the cost associated to all the wells should be considered by the project (e.g. abandonment costs should be included in the cost estimates in case of selecting the options of drilling new wells).
- Reduce (or eliminate) the requirement to bring a rig in the middle of the project.
- Minimise complexity and cost of any well work. Uncomplicated well design.
- Facilitate final well abandonment.

2.3 Peterhead – Goldeneye CCS information

The following information will affect the completion type in the CO_2 injector wells.

2.3.1 General information

Table 2-2: Completion requirement. General information

Name	Goldeneye

Area	North Sea
Located	100km northeast of St Fergus
Basin	South Halibut Basin of the Outer Moray Firth
Platform	Normally Unattended Installation (NUI)
Legs	4
Pipeline to shore	102km, 20" [508mm] diameter
Reservoir	Lower cretaceous Captain sandstone Captain E, D (main) and C (not penetrated by the existing wells)

2.3.2 Goldeneye field - main stratigraphy

The injection reservoir is the Captain formation. The Rodby shales and Hidra marl are the main shales above the injection reservoir.

Vertical containment is provided by the 300m thick primary storage seal, a package including part of the Upper Valhall Formation, Rødby Formation, Hidra Formation and the Plenus Marl Bed.

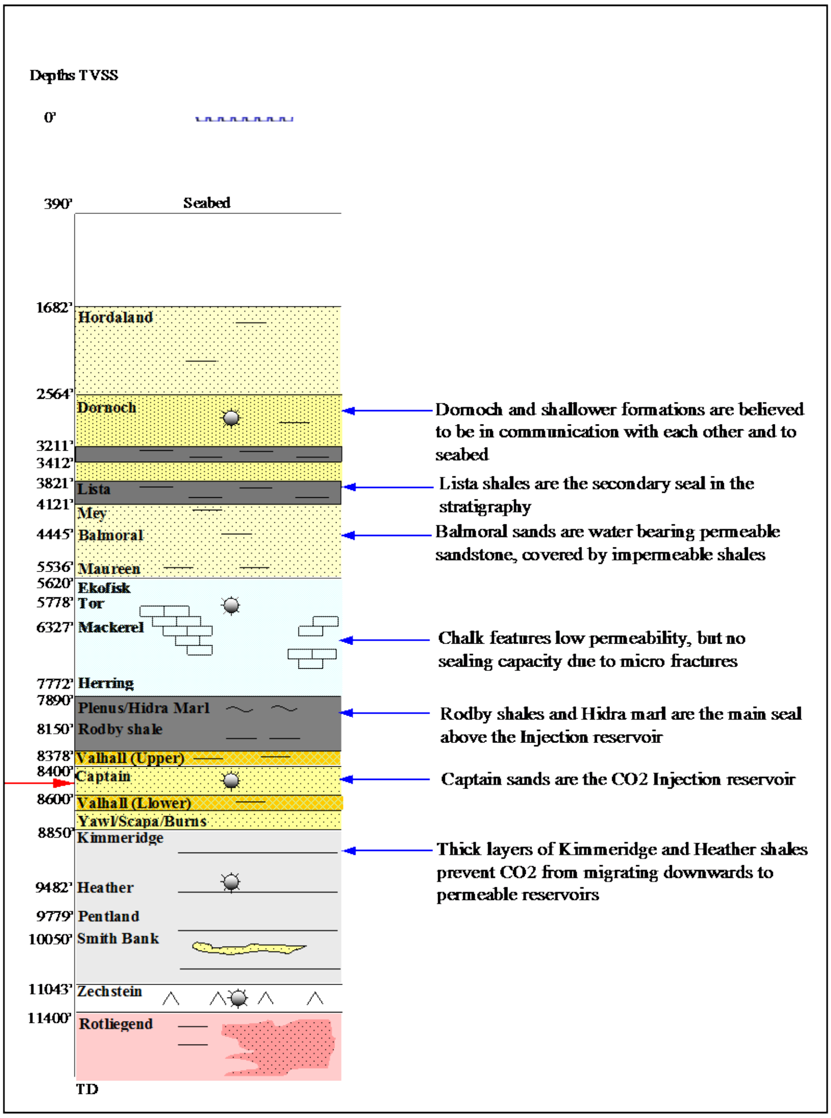


Figure 2-1: Main stratigraphy for Goldeneye area, average depths of formation tops

2.3.3 Reservoir characteristics

Table 2-3: Completion requirement. Reservoir characteristics

Type	Sandstone Captain formation. Main formation is the Captain D
Formation temperature	~83°C @ 8400ft [2560m] TVDss
	Reduction of temperature around the injectors due to cold CO_2 injection (~20-35°C bottom hole injection temperature)
Formation Water	Formation water present in the bottom of the well.
	Water will be initially at the sand face. Evidence of water from downhole pressure gauges in GYA03.
	Formation water around the wellbore will reduce significantly after 6 to 9 months of continuous CO_2 injection. However, water might come back to the formation is not enough CO_2 is injected in the well.
Average Reservoir (Captain D) Porosity and Permeability	~25% porosity ~790md permeability The Captain D is a clean sandstone with very high Net to Gross Captain D presented an excellent connectivity during the hydrocarbon production phase.
Pressure Regime	(The pressure regime is given as an indication for general well/completion design selection. This will be re-calculated before any well operation and before working over the wells). An active aquifer supports the field. All the wells are currently shut in due to water breakthrough and isolated with deep and shallow downhole plugs.
	Original Reservoir Pressure ~ 3830psia [264bara] @ datum 8400 ft TVDss Minimum Reservoir pressure after depletion ~ 2100psia [145bara] @ datum Current pressure is ~2620psia [181bara] (@ end of December 2013 @ datum)
	Minimum expected reservoir pressure before CO_2 injection (~Year 2019): 2650psia [183bara], Pressure Gradient Range - 0.319 psia/ft [72mbara/m]
	Maximum expected reservoir pressure after 10 million tonne of CO_2– (~Year 2031) 3450psia [238bara] @ 8400ft TVDSS, Pressure Gradient: 0.416psia/ft [94mbara/m] Information is of enough quality for this analysis/report on completion concept select. This pressure information will be updated during FEED for the detail design of the wells. Different section of tubing (4½" and 3½" [114mm and 89mm]) to be installed in each well will depend on this information.

2.3.4 Fluids characteristics

Table 2-4: Completion requirement. Fluids characteristics

<table>
<tr>
<td>CO_2</td>
<td>Almost pure dehydrated CO_2 will be available at the platform level. CO_2 specification as follows:
<table>
<tr><td>Compound</td><td>% Fraction mol</td></tr>
<tr><td>CO_2</td><td>0.999883</td></tr>
<tr><td>N_2</td><td>0.000061</td></tr>
<tr><td>O_2</td><td>0.000001</td></tr>
<tr><td>H_2O</td><td>0.000050</td></tr>
<tr><td>H_2</td><td>0.000005</td></tr>
</table>

O_2 level specification is determined by the presence of 13Cr material in the wells.
Water is controlled to avoid hydrates and corrosion in the offshore pipeline (50 ppm mol of water = 20 ppm weight of water)</td>
</tr>
<tr>
<td>Formation Water</td>
<td>Water will be initially at the sand face. Water breakthrough observed in all wells during the production phase. Evidence of water from downhole pressure gauges in GYA03.
Salinity- Total Dissolved Solids (TDS): ~56000ppm (52000ppm – Sodium Chloride - NaCl)
Water level in the wells is currently not known.
It is expected to have more water in the wells at the workover time due to aquifer presence.</td>
</tr>
<tr>
<td>Hydrocarbon</td>
<td>Gas – Condensate
0.37% mol CO_2
0% H_2S
No solids production observed in the facilities
There was a thin (7m) oil rim in the reservoir at original conditions.</td>
</tr>
</table>

CO_2 injection rates and condition

Table 2-5: Completion requirement. CO_2 injection rates and condition

Total CO_2 available	The project requires to inject 10 million tonnes of CO_2 Design Rate (capacity of the capture plant): 138.3 tonnes/h equivalent to 63 MMscfd Normal Operating Conditions ~ 130 tonnes/h (59 MMscfd) Turndown Rate of surface facilities ~ 89.9 tonnes/h (65% of the design case, 41 MMscfd) It is estimated that the injection will take place over a period of 12 years for the 10 million tonnes (including downtime).
CO_2 fluctuation	For the first 5 years of the injection, project will operate with turndown case of 75% (103.8 tonnes/h, 47 MMscfd) For the rest of the injection years, the turndown case will be 65%. All the surface equipment should be design to minimum turndown of 65%. The reference case is to operate the capture plant at based load (i.e. continuous flow) during the first five years on injection. Daily fluctuations between the design rate and the minimum (65% of the design rate) might be carried out after year 5 of injection. Frequent (daily) on and off periods of the capture plant are not planned. A limited packing capacity exists in the offshore pipeline operated in dense phase CO_2 (estimated to be between 2 to 4 hours of CO_2 injection depending on the conditions of the pipeline).
Arrival Pressure and Temperature conditions	The CO_2 will be transported to the platform in dense phase. The maximum pressure of the offshore pipeline is 120bara. This is limited by the operating pressure of the offshore pipeline. The CO_2 will arrive cold to the platform according to the seabed temperature with some changes of temperature in the platform riser. Variations in temperature exist between summer and winter.

2.3.5 Existing wells summary

Table 2-6: Completion requirement. Existing wells summary

Attribute	Data
On/Offshore	Offshore
Well type	Previously Hydrocarbon producer. Currently closed in and suspended with deep set downhole plugs To be converted to CO_2 injection
DFE (ft)	152.5 [46.5m] (Drilling Rig)
Water depth (ft)	395 [120m]
Number of wells	5 existing, 3 slots available
Top reservoir (ft TVDSS)	~8300 [2530m]

There are five existing wells (GYA01, GYA02S1, GYA03, GYA04, and GYA05) in Goldeneye field.

The upper and lower completion specifications of the current completion are:

- Upper Completion

SSSV 5.875" [149mm], 7" [178mm] tubing 6.184" [157.1mm], 5" [127] tubing 4.67" [118.6mm], PDG 4.576" [116.23mm], Polished Bore Receptacle (PBR) 4.577" [116.26mm], Packer 4.65"

- Lower Completion

Formation Isolation Valve (FIV) 2.94" [74.68mm], Screens 3.548" [90.12mm], X-over 3.515" [89.28mm]

The maximum well deviation in the wells is (degrees):

Table 2-7: Well deviation of the existing wells

Well	Deviation (Degrees)
GYA-01	36
GYA-02S1	60
GYA-03	40
GYA-04	68
GYA-05	7 (shortest well)

An intervention campaign was carried out in 2012 and suspension plugs were set in all the wells. At the time some safety valve control line integrity issues were noted on wells GYA01 and GYA03 and corrective measures were required to some tree valves.

In a number of wells (GYA02, GYA04 and GYA05) the lowermost suspension plug was set above the downhole gauge thereby allowing the reservoir pressure and temperature to be monitored, Table 2-8.

Table 2-8: Suspension plugs – Setting depths [1ft = 0.3048m]

	GYA01	GYA02	GYA03	GYA04	GYA05
Suspended	Nov 2012	May 2012	April 2012	May 2012	Feb 2013
Plug 01	139ft	124ft	134ft	118ft	148ft
Plug 02	2669ft	10362ft	2618ft	2976ft	7731ft
Plug 03	8595ft		9017ft		
	Gas migration through SSSV control line		Gas migration through SSSV control line		

None of the wells are subject to any integrity issues of note (PCCS-05-PT-ZW-7180-00004 Well Integrity Assessment Report, 2014).

The Figure 2-2 and Figure 2-3 capture the existing well construction elements with respect to the different formations:

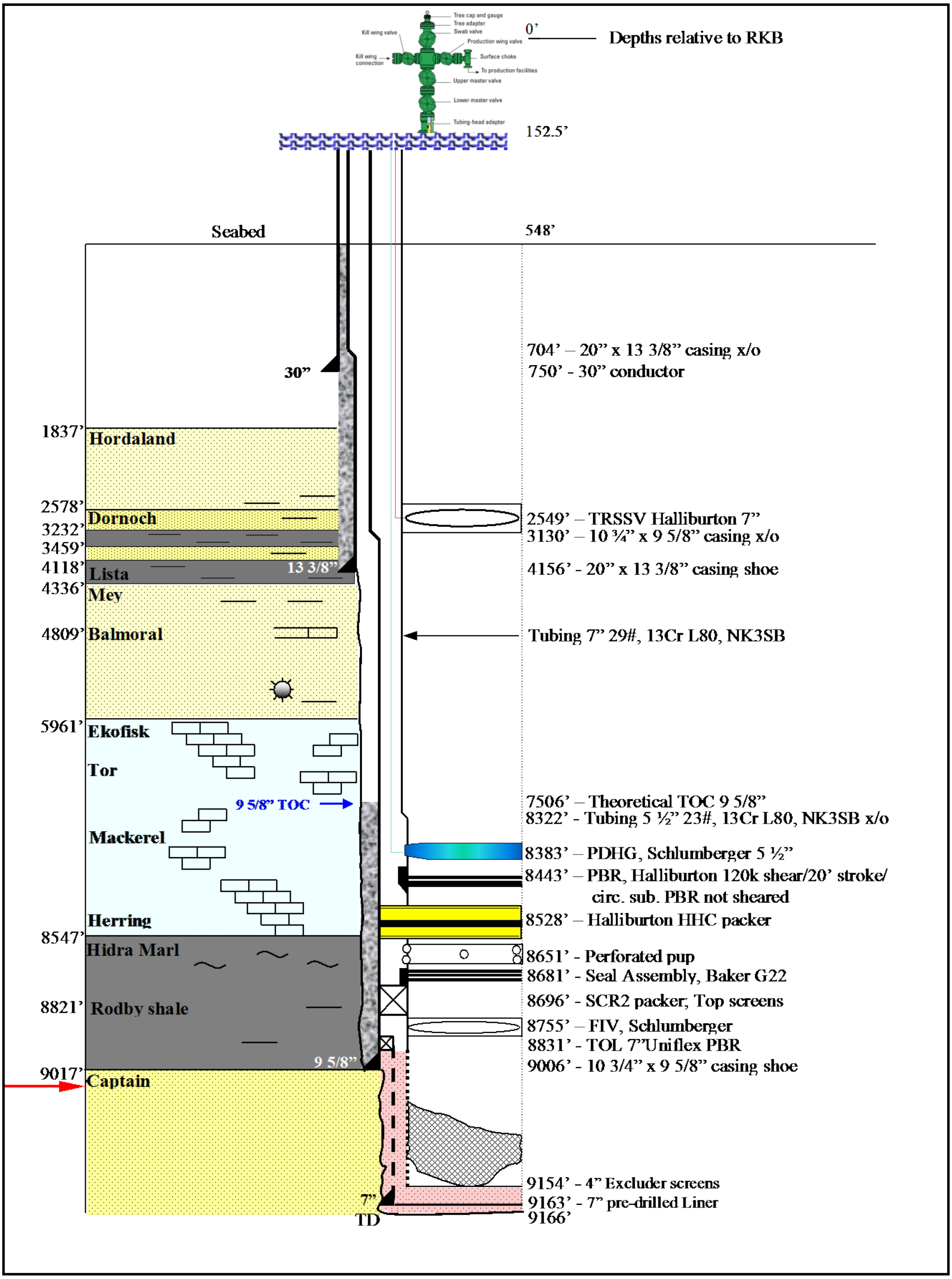


Figure 2-2: GYA01 well schematic including formations (similar completion in GYA05) [1ft = 0.3048m, 1'' = 25.4mm]

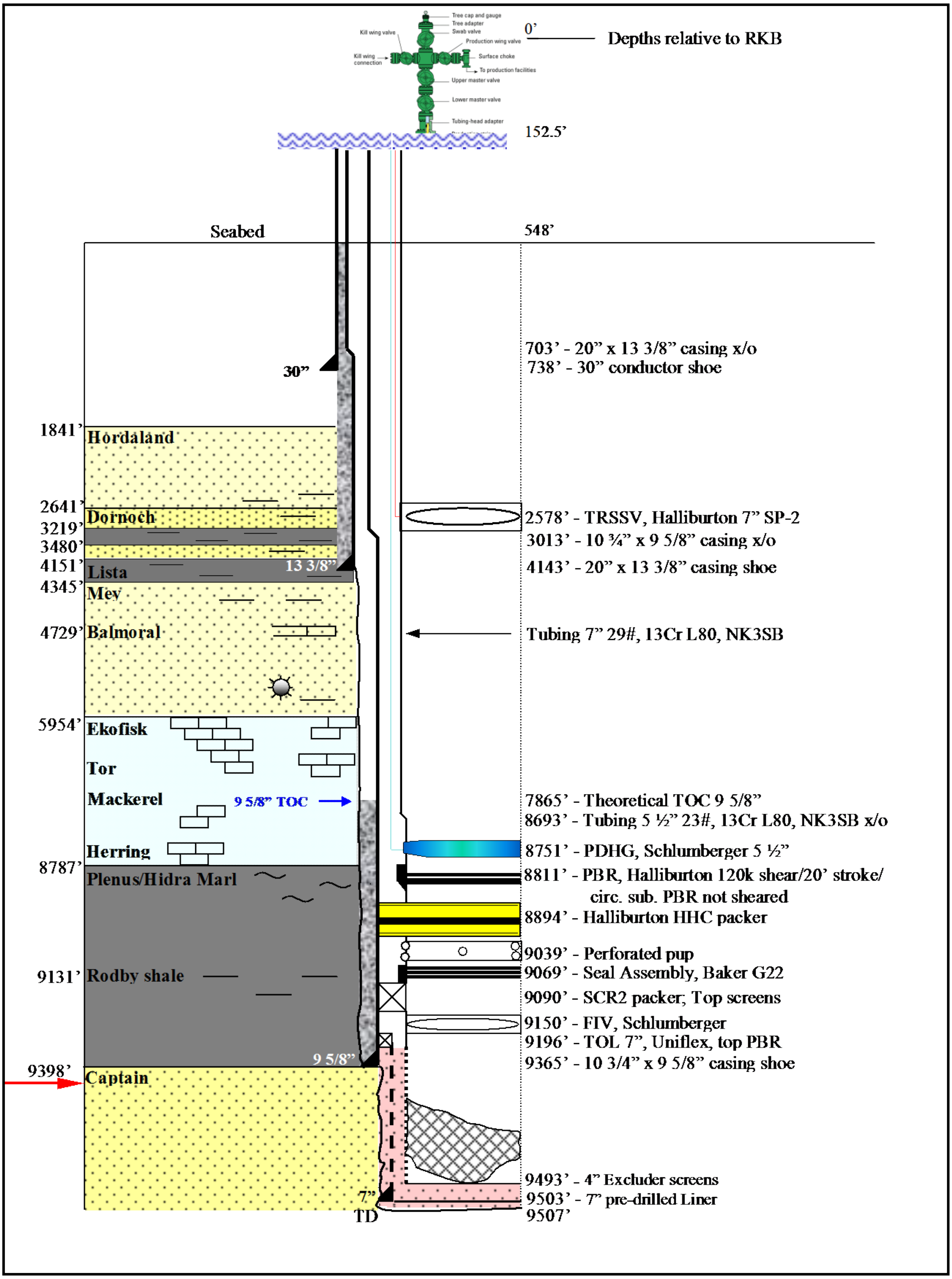


Figure 2-3: GYA03 Completion including completions (similar completion in GYA02S1 and GYA04) [1ft = 0.3048m, 1" = 25.4mm]

3 Injectivity

This section is divided into initial injectivity, long term injectivity management and injection under fracturing conditions.

3.1 Initial injectivity

3.1.1 Reservoir characteristics of the Captain formation

The main factor dictating productivity and injectivity is the quality of the formation. Reservoir quality information is already available from the exploration and appraisal wells drilled in the Goldeneye area and the five hydrocarbon producer wells.

The Early Cretaceous-aged Captain Sandstone Unit, a sandstone turbidite with good reservoir properties, forms the main reservoir (PCCS-05-PT-ZG-05800-00004 Static Model (Field) Report, 2013). Captain formation is represented in Figure 3-1.

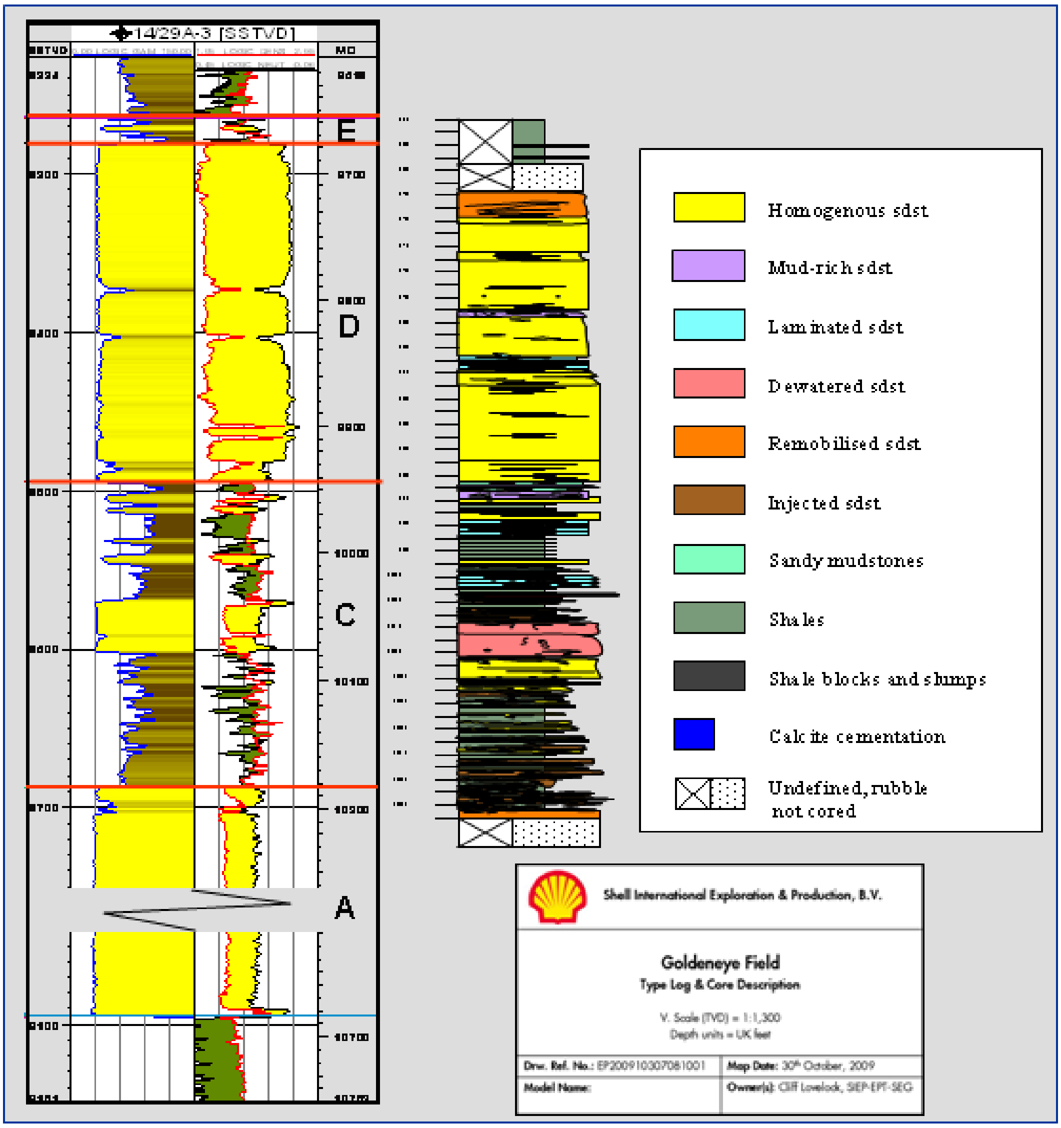


Figure 3-1: Subdivision of the Captain reservoir, Goldeneye area. Log data on left with core faces log description on right. Note unit A is homogenous in parts and highly variable in thickness (shown partial log).

The Captain 'D' is the primary reservoir unit, into which all the development wells have been completed as the primary target. The Captain 'D' unit has been cored in all of the exploration and appraisal wells in the Goldeneye Field. It comprises medium grained massive sandstones that, with the exception of a fining-upwards sequence at the top seen in all wells in the field, show only subtle changes in grain size.

Average porosity of Captain 'D' reservoir is 25% and average permeability is ~790mD (

Figure **3-2**). The average net to gross is 94%. The thickness of the Captain D is 75 to 225ft [22.9 to 68.6m] True Vertical Depth (TVD) with an average of 130ft [39.6m]. These are the primary indicators that we can expect good CO_2 injectivity in Goldeneye.

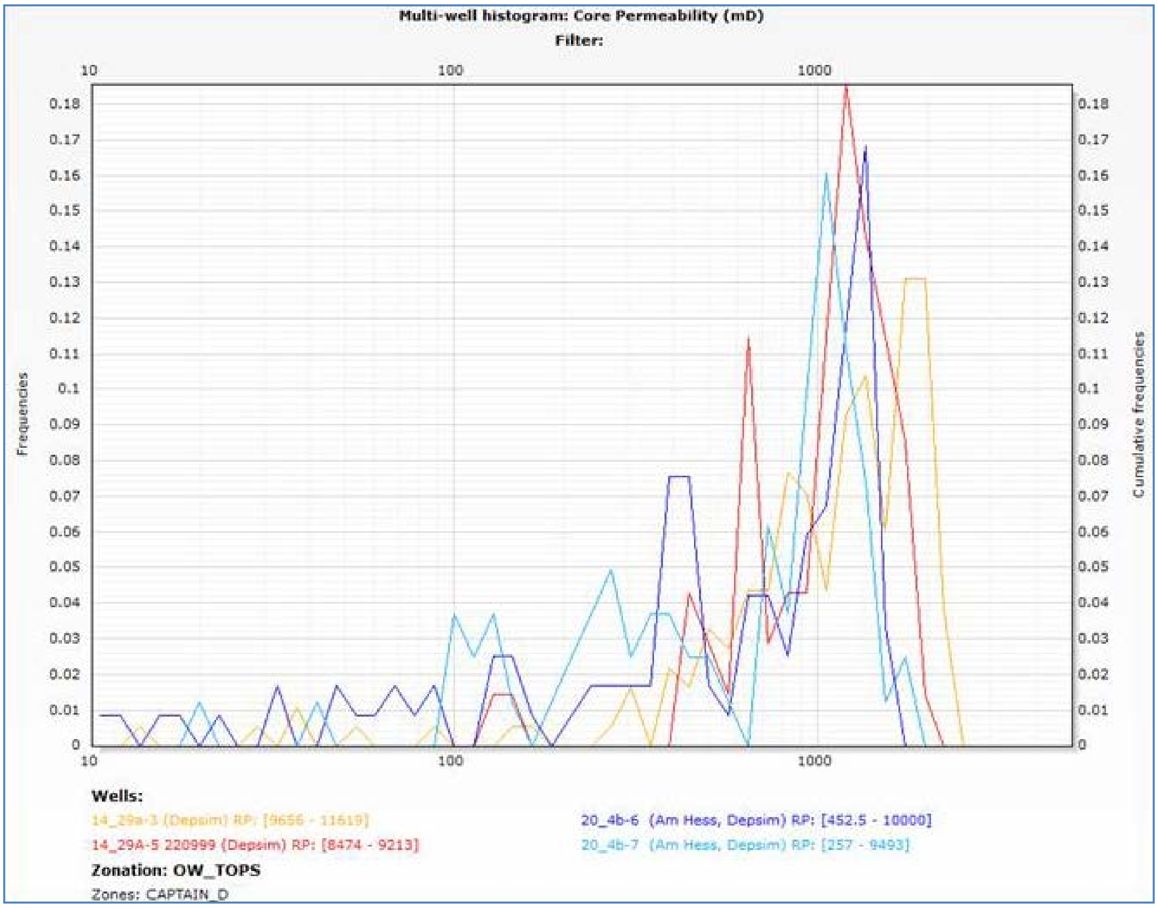


Figure 3-2: Permeability histogram from available cores in the Captain D formation.

All the available wells were completed in the top of the Captain D formation (60ft [18.3m] true vertical). The 9-5/8" [245mm] casing was set in the Rodby formation. The Captain D and E are open to the gravel pack and screens. The Captain E characteristics are poor with average net to gross of 61%, average net porosity of 21% and average permeability of only 150mD. Clearly the contribution of the Captain E with respect to the Captain D is negligible.

The Captain D formation is well connected based on production and pressure information collected during the hydrocarbon production phase.

3.1.2 Hydrocarbon Productivity Phase

The existing wells were completed in the top of the main reservoir Captain D; the wells are also exposed to the poor reservoir Captain E and a short section of the Rodby seal. The 'skin' is high (~80) from the initial completion, probably due to shale section from the Rodby entraining into the gravel.

The best information available to estimate the future CO_2 injectivity is the well's hydrocarbon productivity. This productivity was been excellent despite the high skin and has confirmed the reservoir characteristics.

The gas production rate during the initial clean-up (after completion) was between 90 to 105 million scf/d per well [3.2 to 3.7 million sm^3/d]. The **Figure 3-3** shows the behaviour of the wells during the clean-up.

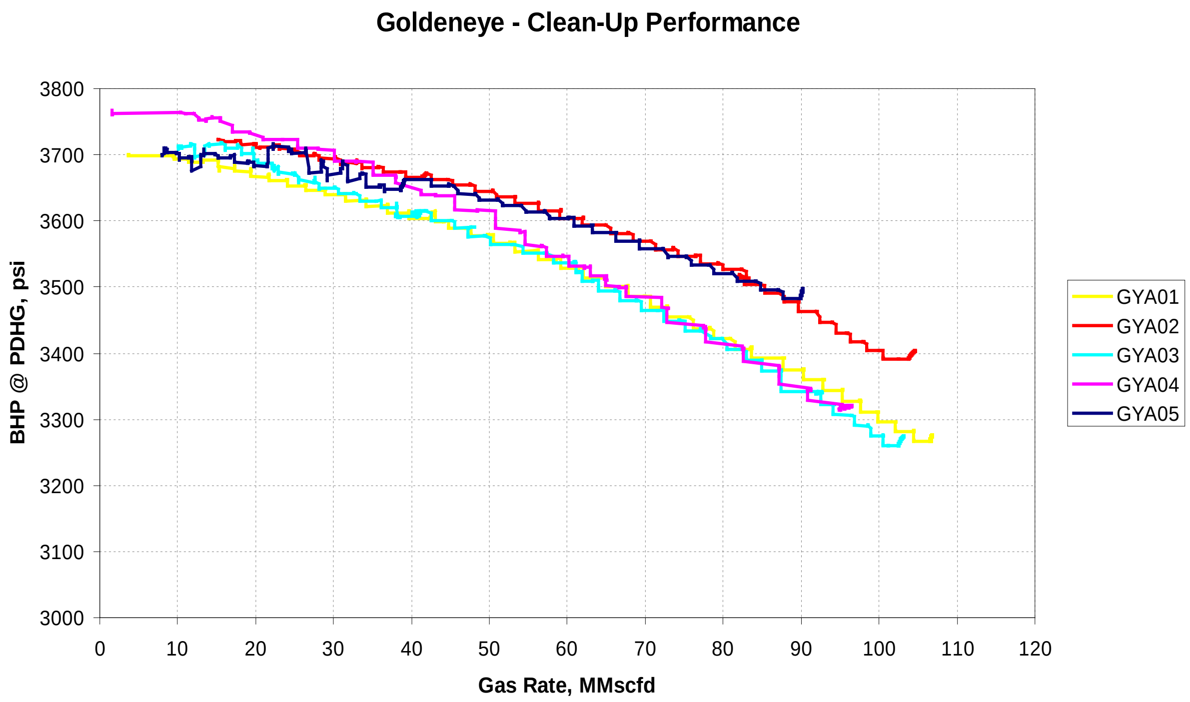


Figure 3-3: Goldeneye hydrocarbon production. Clean-Up performance.

The high productivity was maintained during the production life of the wells. In general, low drawdown levels have been required (150-200psia [10.3 – 13.8bara] drawdown for 60 million scf/d [2.1 million sm^3/d] production). The well productivity was stable during the production time, demonstrating no impairment with time. This can be observed in the **Figure 3-4** for GYA01 (note that the other wells have similar performance). Similar productivity was observed for the five producing wells.

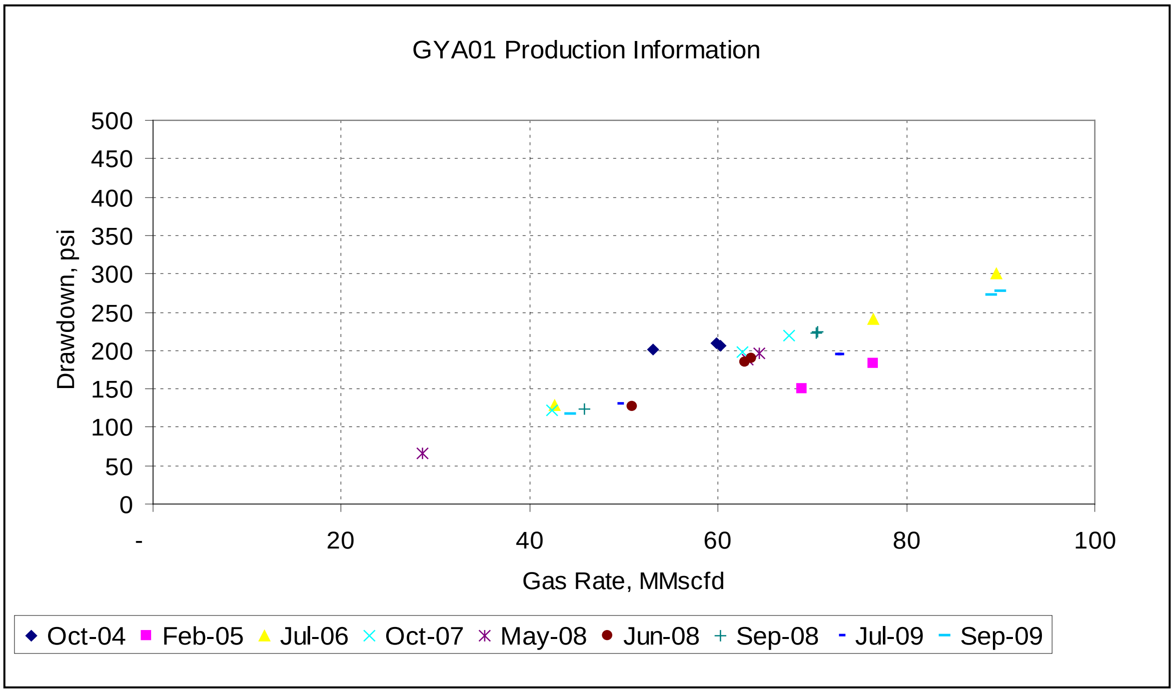


Figure 3-4: GYA01. Productivity history

There are minor differences between the wells as can be observed in the following graph. GYA02S1 and GYA05 are a bit stronger than the rest of the wells (in line with the initial clean-up of the wells).

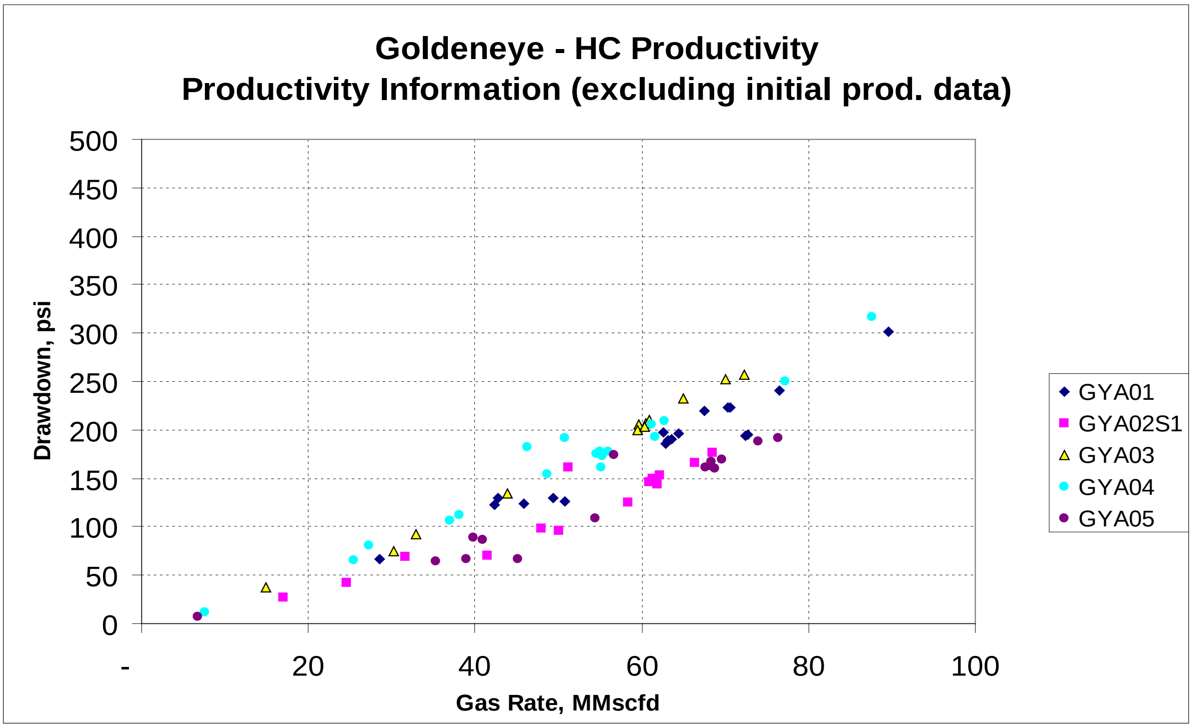


Figure 3-5: Productivity per well during long term production phase

Inflow Performance from gas wells can be represented mathematically using the Jones equation, as follows:

$P_{reservoir}^2 - P_{wf}^2$ = Darcy coefficient * Q + Non-Darcy coefficient * Q^2

Based on the well performance the wells can be grouped in two sets:
GYA01, GYA03 and GYA04
GYA02S1 and GYA05

The calculated coefficients considering the production information are as follows
GYA01, GYA03 and GYA04
Darcy coefficient: 0.0017bar^2/ (sm^3/d)
Non-Darcy coefficient: 4 E-10bar^2/(sm^3/d)^2
GYA02S1, GYA05
Darcy coefficient: 0.001bar^2/ (sm^3/d)
Non-Darcy coefficient: 4 E-10bar^2/(sm^3/d)^2

These are graphically presented in the following **Figure 3-6**:

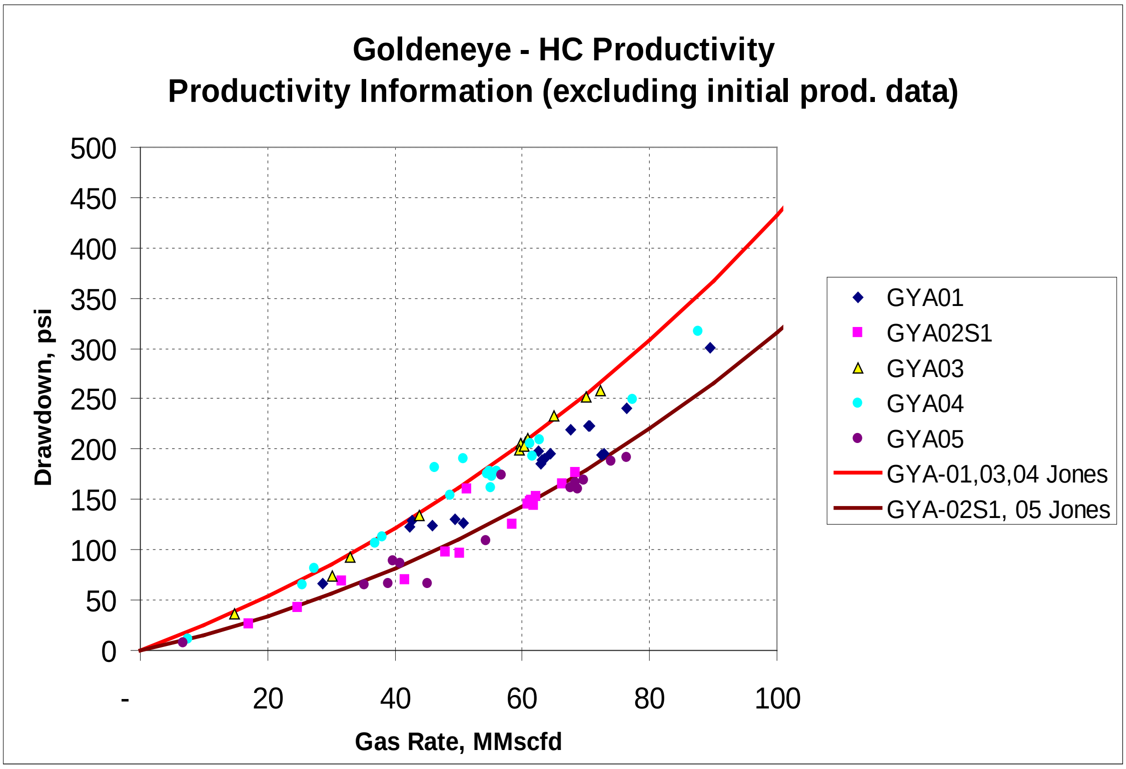


Figure 3-6: Productivity. Jones representation.

3.1.3 Correction of hydrocarbon productivity for CO_2 injection due to PVT changes

This section relates to the correction of hydrocarbon productivity to obtain CO_2 injectivity based on the different flowing properties of the hydrocarbon and CO_2. Relative permeability is not included in this section.

The CO_2 injectivity will be different to the hydrocarbon productivity due to differences in the PVT properties between the hydrocarbon gas produced and the CO_2 injection. The magnitude is relatively small, for example for the maximum rate of 63MMscf/d (138.3 tonnes/h) flow the drawdown under hydrocarbon gas production was between 150 to 200psia, whilst for CO_2 the injection would be between 280psia [19.3bara] and 380psia [26.2bara] above the reservoir pressure depending on the well.

The reservoir pressure just before the CO_2 injection is estimated at 2650psia [183bara]. The required bottom hole pressure is higher than the critical pressure of the CO_2. At reservoir temperature, the CO_2 will be supercritical whilst at the injection temperature the CO_2 can be considered as liquid or supercritical fluid depending on the injection temperature. The viscosity of the CO_2 will be higher than the viscosity of the hydrocarbon gas.

The downhole in situ rate of the CO_2 has a high dependency on the pressure and temperature, but the effect is less pronounced in case of injecting at high pressures as encountered in the Goldeneye reservoir. The downhole rate of the CO_2 for a given surface rate is much smaller than the hydrocarbon production. Both effects are illustrated in the following Figure 3-7 and Figure 3-8:

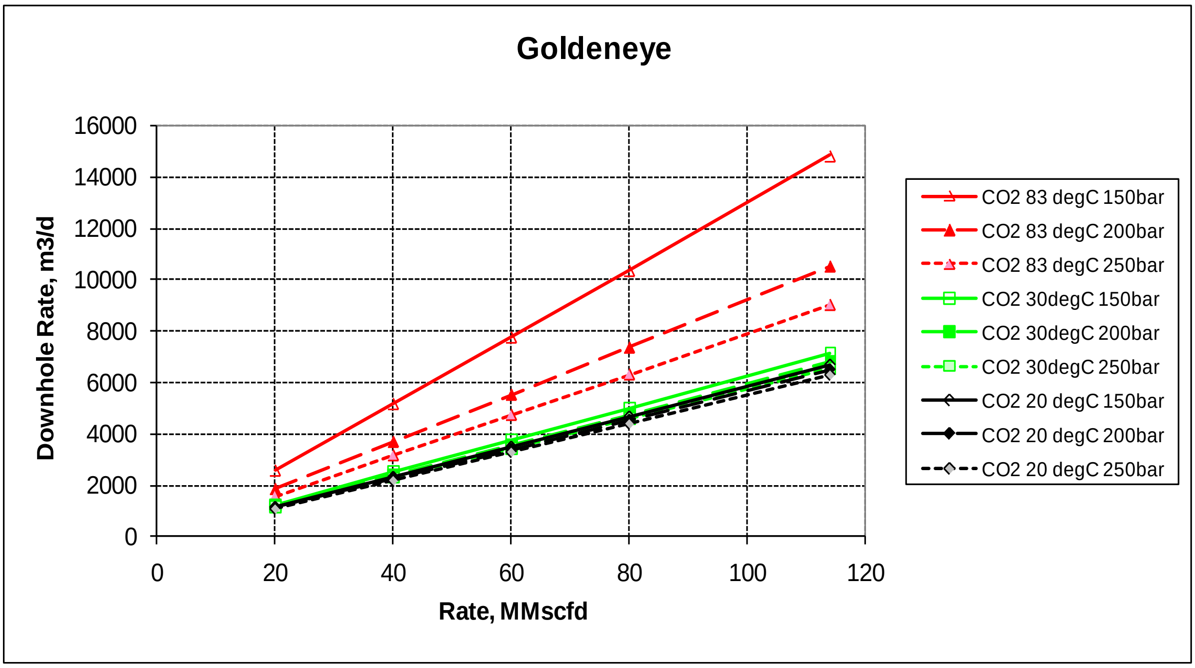


Figure 3-7: CO_2 downhole (in-situ) injection rate for given surface rate

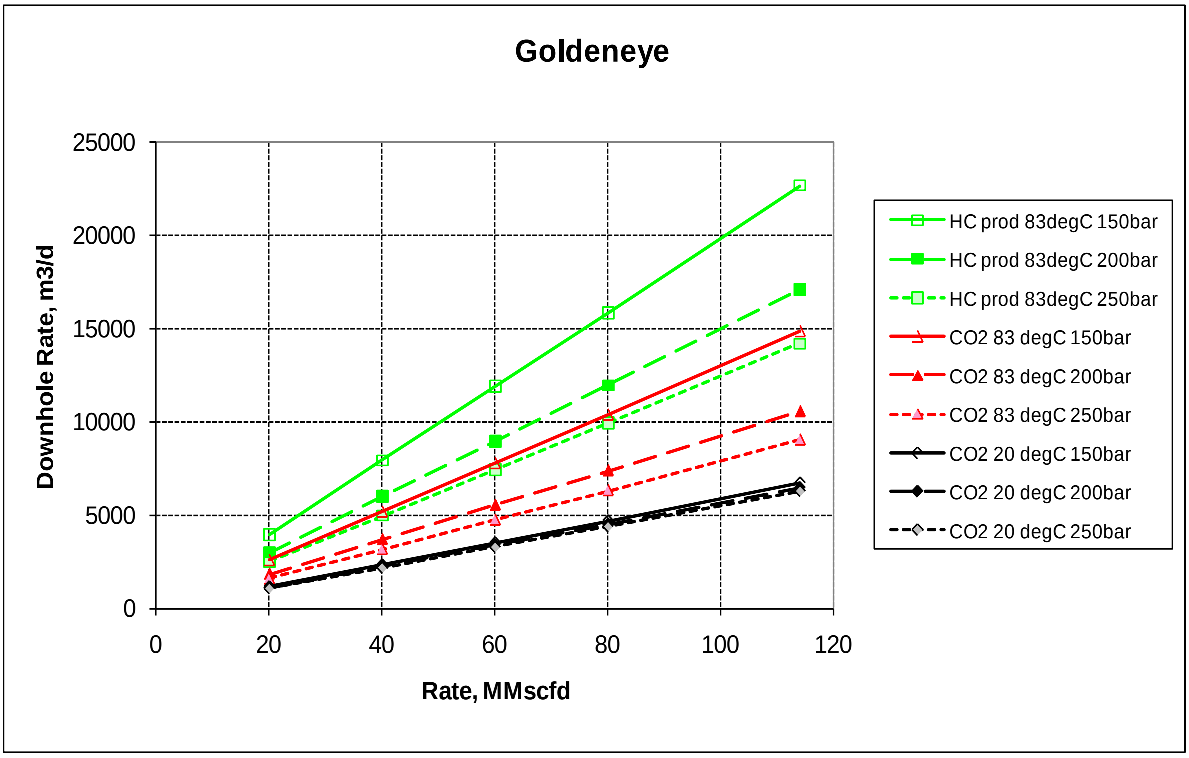


Figure 3-8: Comparison of CO_2 and hydrocarbon downhole rates

The viscosity of the CO_2 is higher than the viscosity of the hydrocarbon gas in Goldeneye (see Figure below). This difference in properties will have a negative effect on the injectivity.

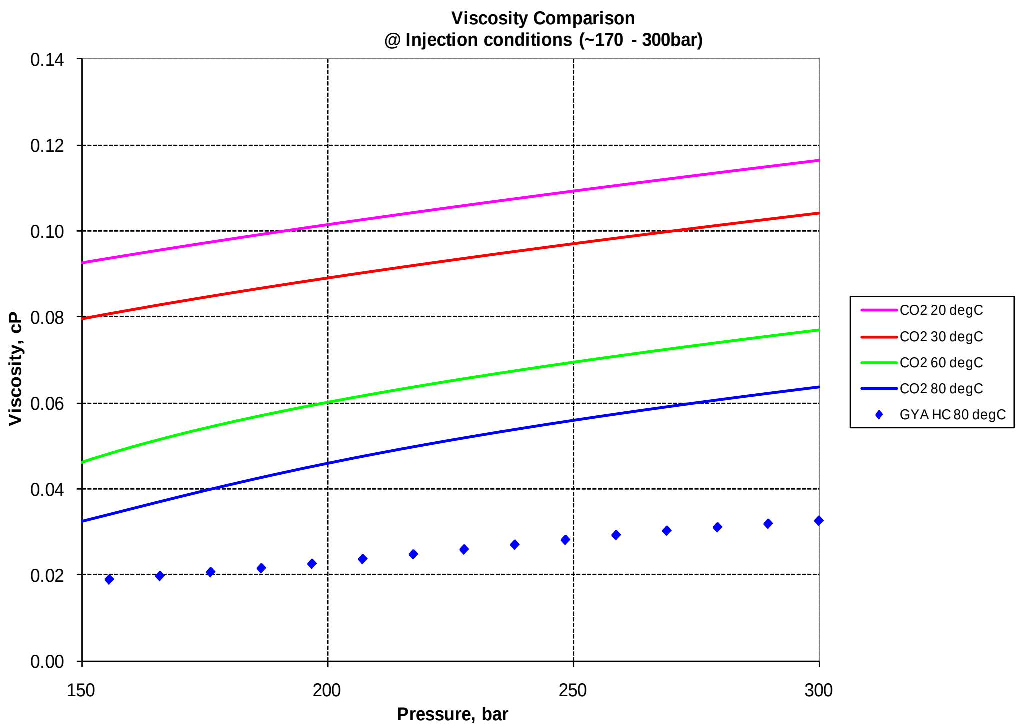


Figure 3-9: Comparison of Viscosity between CO_2 and hydrocarbon gas.

The difference between CO_2 and hydrocarbon gas in terms of equivalent downhole rate and viscosity can be calculated with the previously calculated Jones equation as follows:

$$P_r^2 - P_{wf}^2 = Aq + Fq^2$$

$$A_{CO2} = A_{gas} \frac{\mu_{CO2}}{\mu_{gas}} \frac{Z_{CO2}}{Z_{gas}} \frac{T_{CO2}}{T_{gas}} = A_{gas} K_A$$

$$F_{CO2} = F_{gas} \frac{Z_{CO2}}{Z_{gas}} \frac{\gamma_{CO2}}{\gamma_{gas}} \frac{T_{CO2}}{T_{gas}} = F_{gas} K_F$$

Where,

$\frac{\mu_{CO2}}{\mu_{gas}}$	Viscosity relation CO_2 / hydrocarbon gas
$\frac{Z_{CO2}}{Z_{gas}}$	Compressibility Factor relation CO_2/ hydrocarbon gas
$\frac{T_{CO2}}{T_{gas}}$	Bottomhole injection temperature relation CO_2 / hydrocarbon gas
$\frac{\gamma_{CO2}}{\gamma_{gas}}$	Specific Gravity relation CO_2 / hydrocarbon gas

A the Darcy coefficient and F the Non Darcy coefficient.

The main assumptions to the equation are:

- same permeability, skin and drainage radius for CO_2 and gas
- No complex reservoir effects (e.g. well interference, external behaviour, etc.)
- Relative permeability effects not included
- CO_2-rock chemical reaction not included
- Matrix injection

Because of the variable properties of the CO_2 (Z factor, viscosity and density) with pressure and temperature the injectivity will vary with these factors. However the effect is relatively small as can be observed in the following figures where the CO_2 injectivity is shown at different pressures and temperatures.

For the maximum considered rate of 63MMscf/d then the delta pressure is in the order of 280psia [19.3bara] and 380psia [26.2bara].

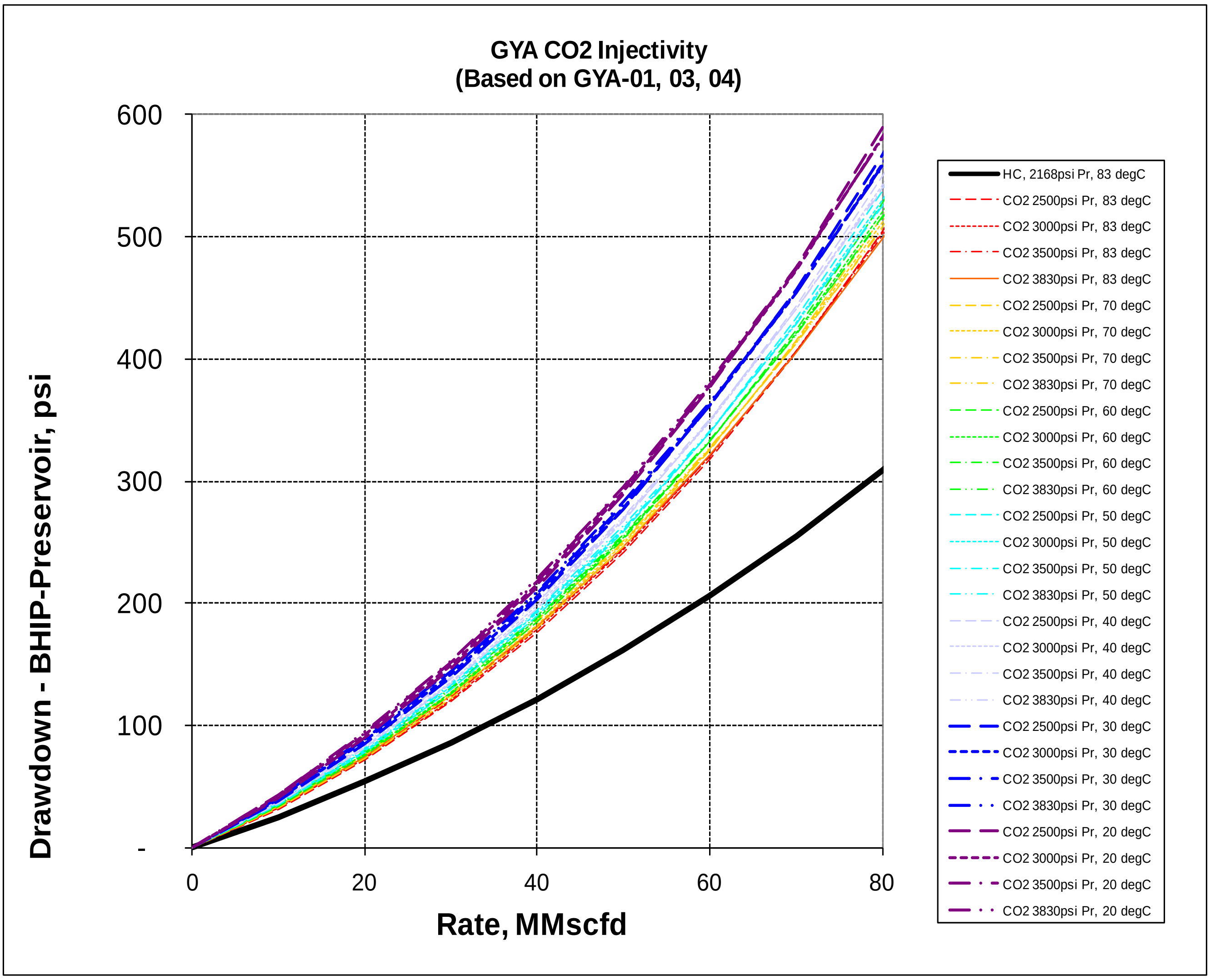


Figure 3-10: CO_2 injectivity in comparison to hydrocarbon productivity (GYA01, GYA03 and GYA04)

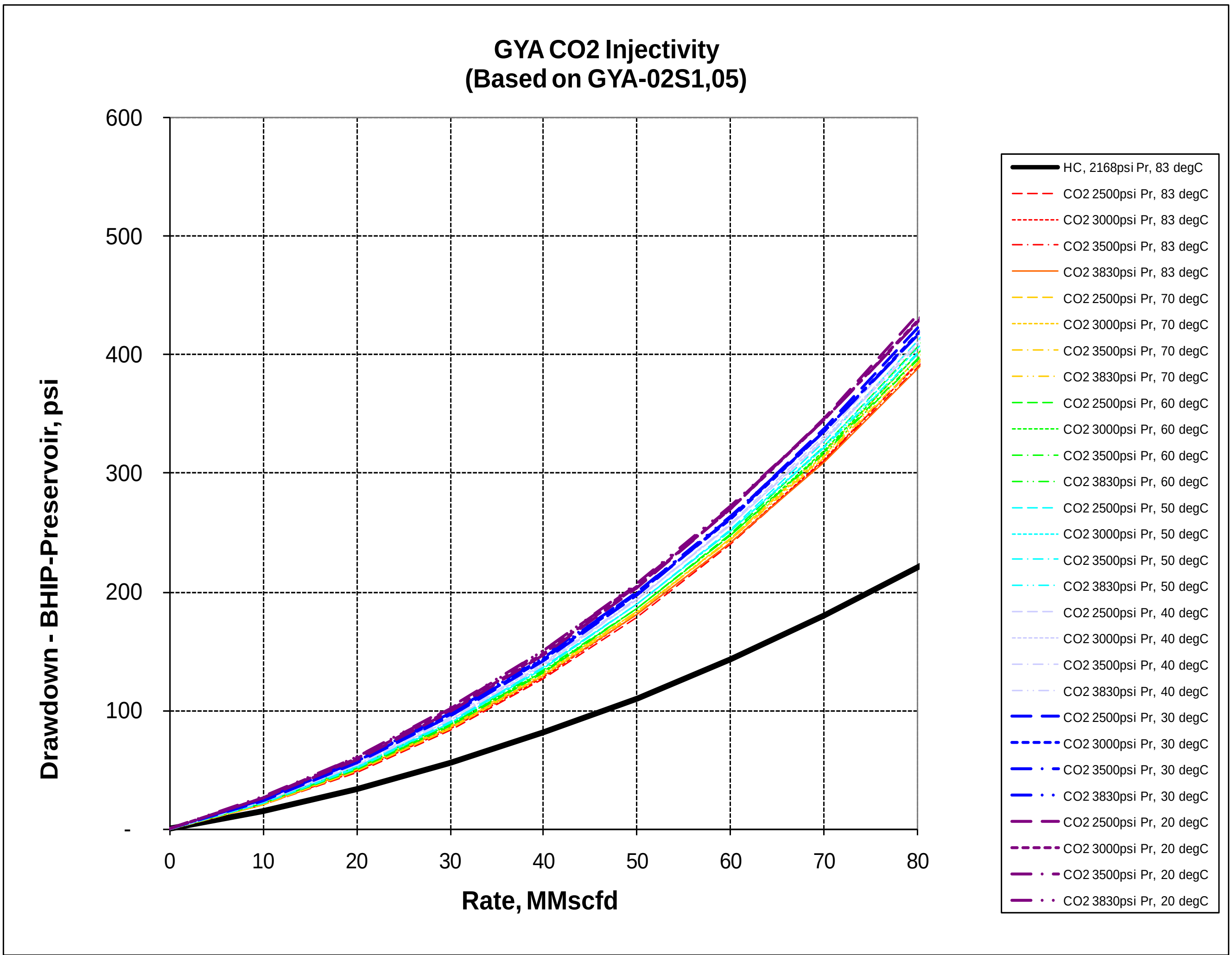


Figure 3-11: CO_2 injectivity in comparison to hydrocarbon productivity (GYA02S1 and GYA05)

3.1.4 Relative permeability

The CO_2 injection in Goldeneye will be a gravity-dominated process, where the microscopic displacement efficiency is quite high, even though in the near wellbore area there will still be a viscous displacement. Nevertheless, the density difference of the fluids in addition to high rock quality in Captain sands, will generate a strong segregation and the displacement process will be gravity dominated. This will reduce water saturation to small values, where the relative permeability should be very low for water and high for the CO_2. So we can expect the CO_2 to have a favourable mobility ratio and, as a consequence, good injectivity.

During the Longannet project, the effect on Relative permeability on the injection was investigated. In summary, the modelling results have demonstrated that hysteresis in water permeability has little effect on CO_2 distribution and injector bottom hole pressure, hence injectivity.

This was reported during the Longannet – Goldeneye CCS project in section 3.5 of the report (UKCCS-KT-S7.18-Shell-002 Injectivity Analysis Preparation, 2010).

3.2 Long Term Injectivity Management

3.2.1 Gravel pack and Formation plugging - Filtration

Very small particles can be accepted in the injection wells to avoid plugging at the screens / gravel pack and formation. The recommended values for filtration are 17 microns (section 5.4.7), to avoid plugging of the lower completion in the existing wells and 5 microns to avoid formation plugging (section 3.2.2).

There is a likelihood that following 7 years of production, debris will exist in the offshore pipeline (corrosion products, sand etc.). When flow is reversed in the pipeline, displacement of these products into the wells without any mitigation measures would plug the lower completions (screen-gravel pack) and the formation. Plugging may reduce the injectivity through the lower completion (screens / gravel) and formation with time. Mitigation options related to pipeline commissioning and filtration should therefore be applied to ensure long term injectivity.

The offshore pipeline will be cleaned during the commissioning phase for the Peterhead CCS project. Removal of the solids and liquids during this phase is very important to ensure the long term integrity of the offshore pipeline and the lower completion / formation. Displacement of any pipeline content into the wells during the pipeline-commissioning phase must be avoided in order to preclude damage or impairment of the downhole sand control.

3.2.2 Discussion

The same offshore pipeline currently used for the hydrocarbon production will be used for the CO_2 injection. During the production phase it is possible that corrosion products and / or formation fines might have settled in the pipeline. On commencing CO_2 injection there is the potential that any solid debris present in the pipeline could become mobilised or dislodged and travel down the pipeline to the wellbore, potentially impairing injectivity by physically obstructing the path of CO_2 into the reservoir. As the pipeline is 105km long 20" [508mm] diameter, even a small film of debris may represent a significant risk to injectivity.

In an injection system in the case of having particles bigger than a critical size the solids will start to accumulate internally at the screens, gravel and the formation. Smaller solids can pass the screen but can accumulate at the gravel. Still smaller solids can travel through the gravel and even smaller solids can sail through the formation.

Very small particles can be accepted in the injection wells to avoid plugging at the screens / gravel pack and formation. The accepted level is using the guidelines in the oil industry for flow in a porous media:

- Particles larger than 1/3 of pore throat size will bridge
- Particles smaller than 1/7 of pore throat size will flow through the matrix without plugging.
- Particles between 1/3 and 1/7 of pore throat size will invade and impair the porous media
- Pore throat size is 1/6 of particle size in a packed sand matrix with reasonable sorting

Average pore throat analysis from capillary curves in Captain formation is between 35 to 40 microns.

Particles between 5-12 microns invades and impairs the formation (1/7 – 1/3 formation). Particles smaller than 5 microns sails on through deep into the formation (1/7 formation).

Normally the value for the particle size compatible with the formation (under matrix injection) is estimated using core flood lab experiments and experience in similar formations. The value in Goldeneye was calculated using the average pore throat from petrophysical analysis (mercury injection capillary pressures) and the normally accepted rules in the oil industry for particle management. The average pore throat is in the order of 35-40 micron in line with the average permeability of the formation.

During the hydrocarbon freeing operation in May 2013 (9 pigs sent from platform to beach), the sludge collected contained approximately 1kg of solids. The sample analysis indicated 12% solids with 50% water & 25% condensate. The solids contained 50% iron oxides and the rest acid insoluble compounds (silicates), carbon and other salts and trace materials. Sand was not detected. The only material expected but not present in the samples was Iron Carbonate (FeCO3).

The main threat is perceived to be from the epoxy coating of the pipeline (section 3.2.3). Another possible source of solids will be debris (corrosion products, sand/fines, scale) from the pipeline itself and mol sieve, amine salts, etc. from the conditioning unit.

The quantity of solids that will be present during the injection operation is currently unknown.

The fact that the CO_2 will be dry reduces the risk of having corrosion products injected into the wells.

Filtration will be provided at the Goldeneye platform. It is not expected to have large amount of solids to be produced from the capture plant. Within the compressor package there will be a 5 micron filter.

The current philosophy of the filters at the Goldeneye platform is to prevent exceptional situations (de-bonding of epoxy coating) leading to remedial activities. In other words, the filters will be used to prevent well workovers or stimulations with low chance of success. It is not designed for continuous removal of sustained solids production. It is better to clog a surface filter than the filters (lower completion/formation) downhole in the wells. If the filters clog up, it will be for no apparent reason, and injection should be stopped until the root cause is identified and eliminated.

Filtration units for dense phase CO_2 have been confirmed by the surface facilities to be available in the market. Filtration package will be designed during FEED.

3.2.3 Disbondment of pipeline coating (applicable to existing offshore pipeline)

This risk will be mitigated by the operation of tight control of the quality of the injection gas, and the installation of an appropriate filtration system on the platform upstream of the wells. Again, injection gas quality management will feature in operational procedures that will be developed for the installation

The offshore pipeline was installed with an internal epoxy coating. The internal coating is a solvent based cured epoxy. The coating is not installed to protect against corrosion, it was installed to provide short-term corrosion protection during the pipeline storage and transportation. The thickness of the cured epoxy is between 30-80 microns.

Decompression testing was performed on the section of stock/spare pipe in the warehouse with CO_2 content during Longannet Feed. Decompression testing has provided confidence that the coating is not going to disbond even under very aggressive decompression rates when dense phase CO_2(worse than will be seen in operation) is high and it is not expected that the coating will come off. Nonetheless, a filtration system should be applied/installed.

Although coating disbondment is not expected, there is still some degree of uncertainty of the coating response under CO_2 exposure.

Should disbondment occur during operation then particles ranging from small solids to relatively large fractions of coating may be formed, which could subsequently clog or completely block the gravel pack / formation, thereby reducing injectivity. The mitigation for this case is to have a tight control on the CO_2 quality being injected into the wells using a filtration system on the platform.

3.2.4 Hydrates

The formation of hydrates is only possible when water is present in sufficiently significant quantities and the temperature and pressure of the fluid is within the hydrate formation window. Hydrates will be managed primarily during steady state injection by dehydration of the injection fluids to sufficiently remove the water to inhibit the formation of hydrates.

Free water is not expected in an injection scenario. However, it is possible that water will enter back the wellbore in case of an injection trip when not enough CO_2 is injected to displace the water from the wellbore.

During hydrocarbon production, water encroached into the Goldeneye gas cap and at least part of the well gravel pack will be surrounded by water at the time that injection commences. As such hydrocarbon gas and water will be present during the initial CO_2 injection. The trapped gas saturation is estimated to be 25%, so some methane will remain near the well. The methane is miscible with CO_2 and consequently will eventually be displaced by the injected CO_2. The initial injection of CO_2 will drive water away from a well and cool the reservoir.

In order to reduce the initial risk of hydrate formation during the first years of injection (once water is displaced from the wellbore) it is considered prudent to introduce batch hydrate inhibition prior to operational opening of a well for injection purposes. If water is subsequently introduced into a well and/or it is suspected that water is present in a wellbore, then batch injection should continue. Methanol is currently preferred as an inhibitor and this will be supplied to the platform via the 4" [102mm] piggybacked supply pipeline. Batch hydrate inhibition will feature as an instruction in the well operational procedures that will be developed for the injection system.

3.2.4.1 Hydrates Curves

It is possible to form hydrates from mixtures containing CO_2 /hydrocarbon and water. Hydrate curves for CO_2 and Goldeneye hydrocarbon and their mixtures in the presence of a free water phase are shown in Figure 3-12 (the hydrate region is to the left of the curve). Hydrocarbon hydrates are formed more easily compared to CO_2 hydrates in terms of temperature. For instance, at 2,900psia [200bara] pressure and in the presence of water, hydrocarbon hydrates can be formed at temperatures below 22°C whereas CO_2 hydrates only form below 11°C.

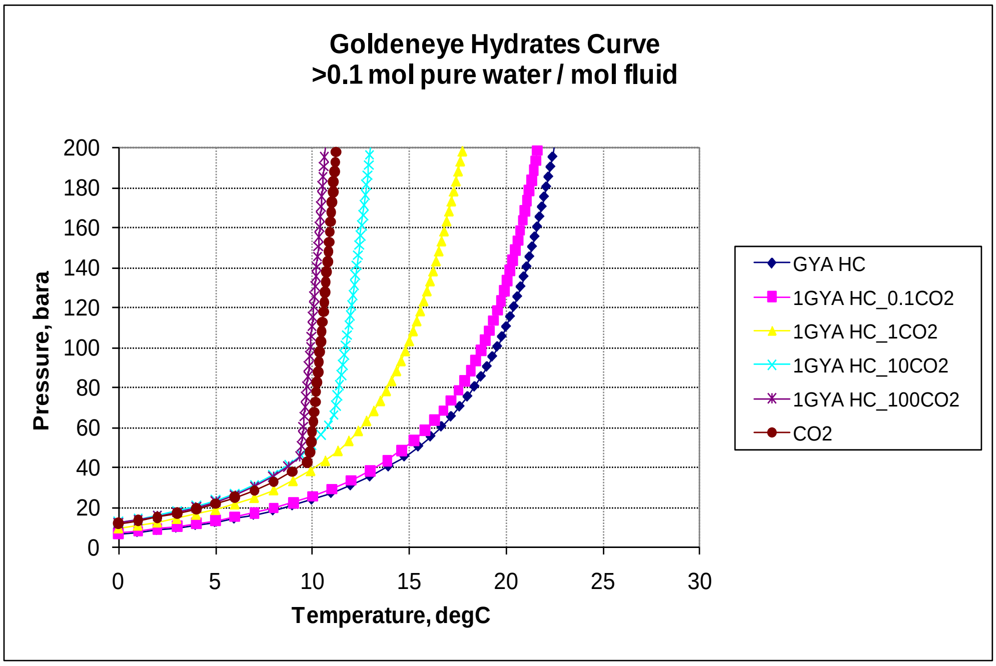


Figure 3-12: Hydrate equilibrium curve for CO_2 and Goldeneye hydrocarbon and their mixtures in the presence of free water.

The CO_2 hydrate equilibrium curve will change due to the reduction of water as shown in Figure 3-13. For low concentrations of water in CO_2, the hydrate equilibrium curve in the liquid CO_2 phase shifts to lower temperatures. This shift is attributed to a shift in solubility of water in the CO_2 liquid phase.

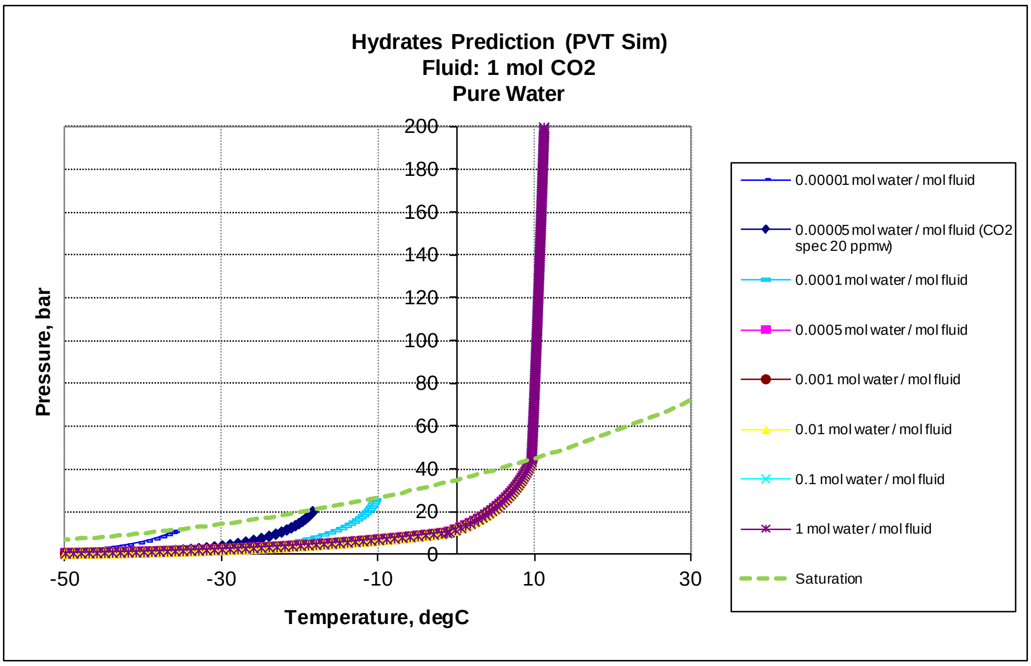


Figure 3-13: Hydrate equilibrium curve for CO_2 at different water concentrations

3.2.4.2 Possibility of Hydrate deposition

Hydrate deposition risks is investigated in the following section for different well conditions.

Normal CO_2 Injection Conditions

The dehydration of the injected fluid effectively inhibits any hydrate formation during normal operating injection conditions of the well.

Free water from the aquifer during this phase is not expected as the water has been displaced by the CO_2 injection. The tubing content is displaced by CO_2 many times.

The injection well will develop cold conditions, the bottom hole injection temperature during normal injection are expected to be between 23°C to 35°C as such there is not an issue of hydrate deposition in terms of injectivity.

This is illustrated in **Figure 3-14** where the injection conditions at the wellhead and bottomhole are plotted against the hydrate equilibrium curve for dehydrated CO_2.

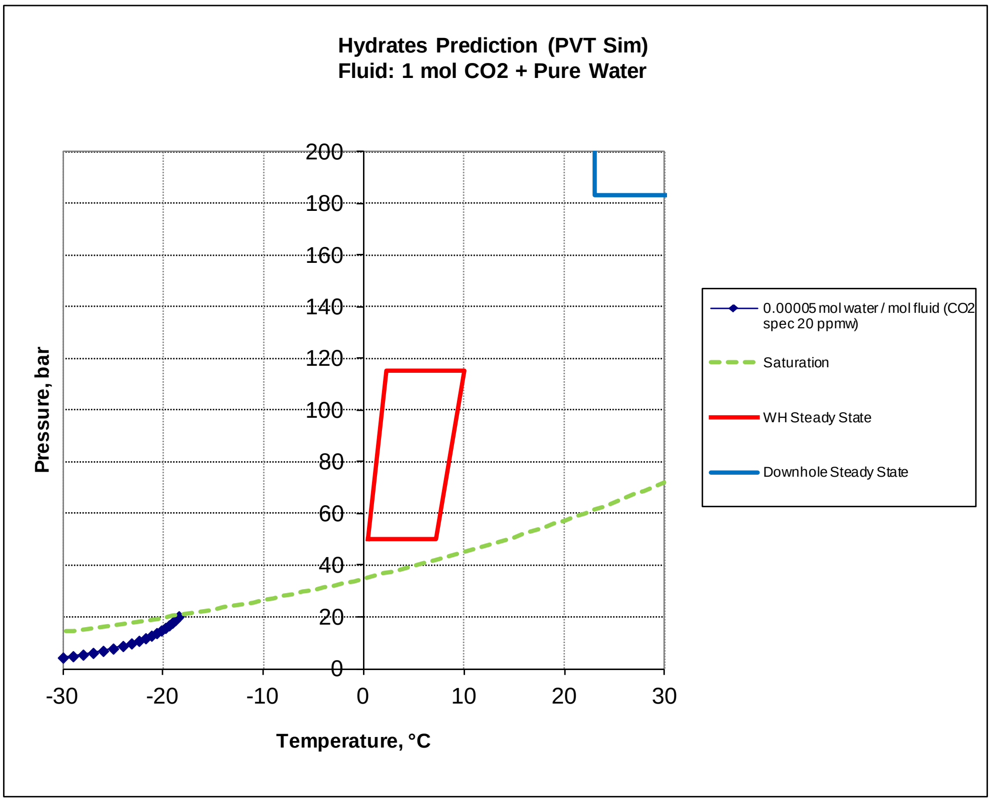


Figure 3-14: Hydrate equilibrium curve and well conditions under normal CO_2 injection conditions

Closing-in operation (Transient)

The bottom part of the well is not in the region to form hydrates. During the short term closed-in operation (hours) it is likely that water is not present in the wellbore (bottom of the well) as per the water has been displaced by the CO_2 injection during the injection time. The well is still injecting CO_2 during the close-in operation as such there is no aquifer influx yet.

The CO_2 in the top of the well will still be dehydrated during this operation. The top of the well will be at saturation conditions (when the reservoir pressure is low) and some liquid CO_2 will evaporate causing a temperature drop. However, there is an insignificant risk of hydrate depositing, Figure 3-15, as after a short time the content of the wellbore will increase in temperature again.

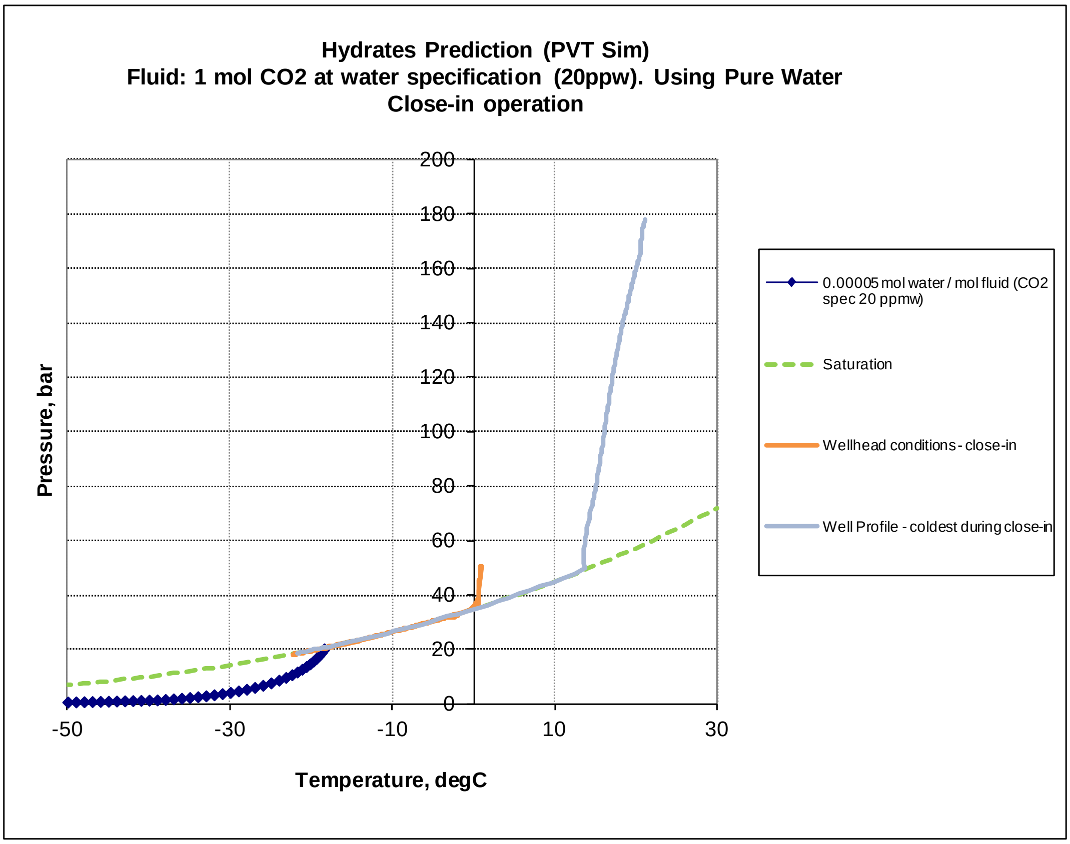


Figure 3-15: Hydrate equilibrium curve and well conditions during close-in operation

Well Closed-in Period

The well will be warming up during this time and will tend to go into the geothermal conditions. The bottom part of the well will be at temperatures above the hydrate equilibrium temperature even assuming free water.

The top part of the well will be warming up, but the pressure and temperature conditions will stay in the hydrate curve assuming free water.

In the case of having dehydrated CO_2 conditions then the risk of hydrates is insignificant at the top of the well and nil at the bottom of the well (similar than the closing-in operation)

Aquifer water might enter the wellbore depending on injection time. There are two predicted cases:

- Water entering the wellbore

When the well is closed-in, water from the aquifer will enter the wellbore due to the aquifer strength. Free water would tend to accumulate in the bottom of the well due to the density difference. The main uncertainty would be the vertical column of water present in the well and the speed is moving upward displacing the CO_2 from the well.

- No water entering the wellbore

With enough CO_2 injection, water from the aquifer is pushed away by the CO_2. The time where the water is not coming back into the well (when it is closed in) is estimated to be between 6 months to 1 year of continuous injection (section 4.6.2 in the report (UKCCS-KT-S7.18-Shell-002 Injectivity Analysis Preparation, 2010)).

After this continuous time of injection the water will tend to stay away from the wellbore. However, in case that the well has injected for a short time then the water may enter the wellbore.

The discussion above is illustrated in the Figure 3-16 below. The top of the well under the presence of free water will enter the hydrate deposition region.

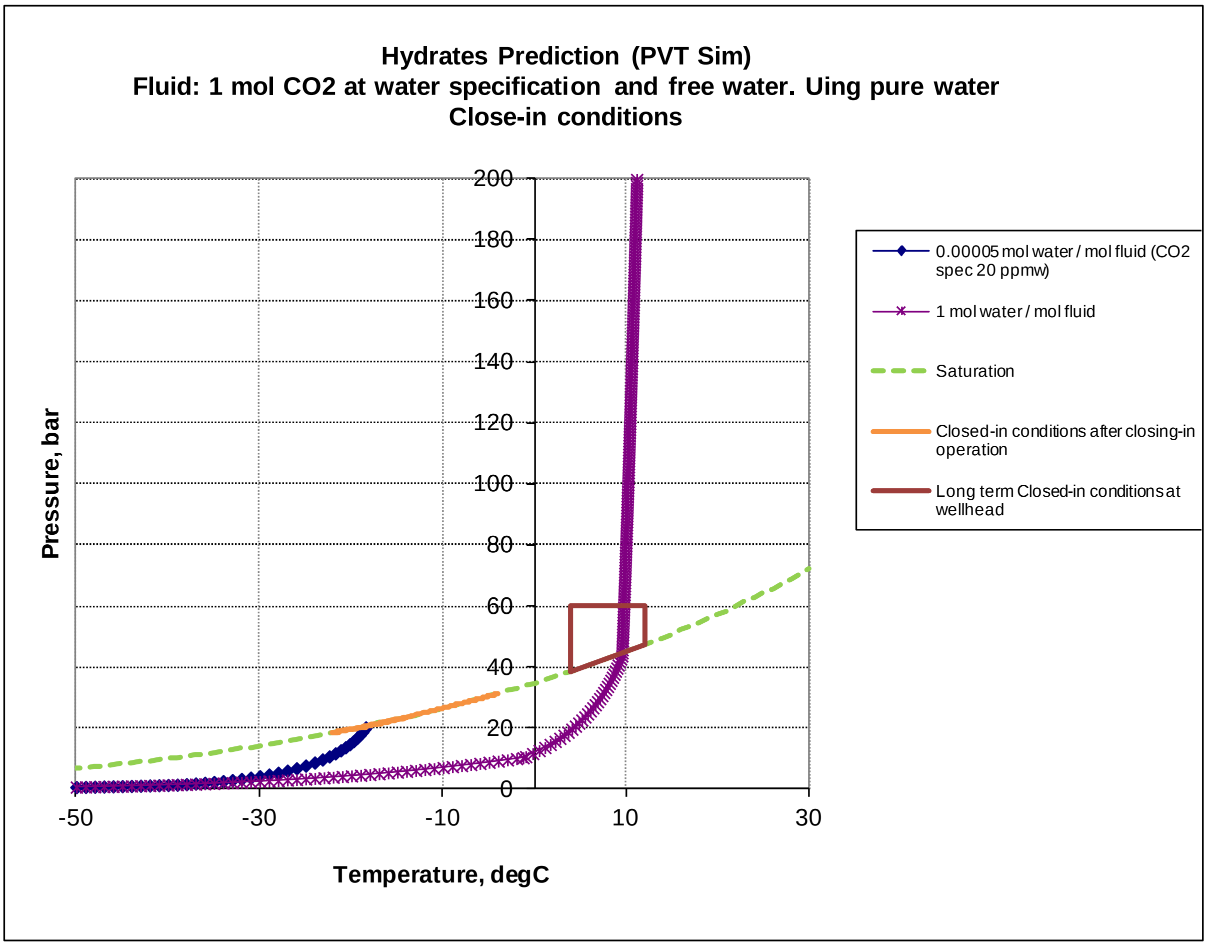


Figure 3-16: Hydrate equilibrium curve and well conditions during closed-in conditions

Starting-Up Operation

Under certain conditions aquifer water has entered into the well during the close-in period (as described above). Considering the cold injection conditions of the CO_2 arriving to the platform and the expansion of the CO_2 during the starting-up operation, hydrate would be formed during this operation in the presence of free water, Figure 3-17.

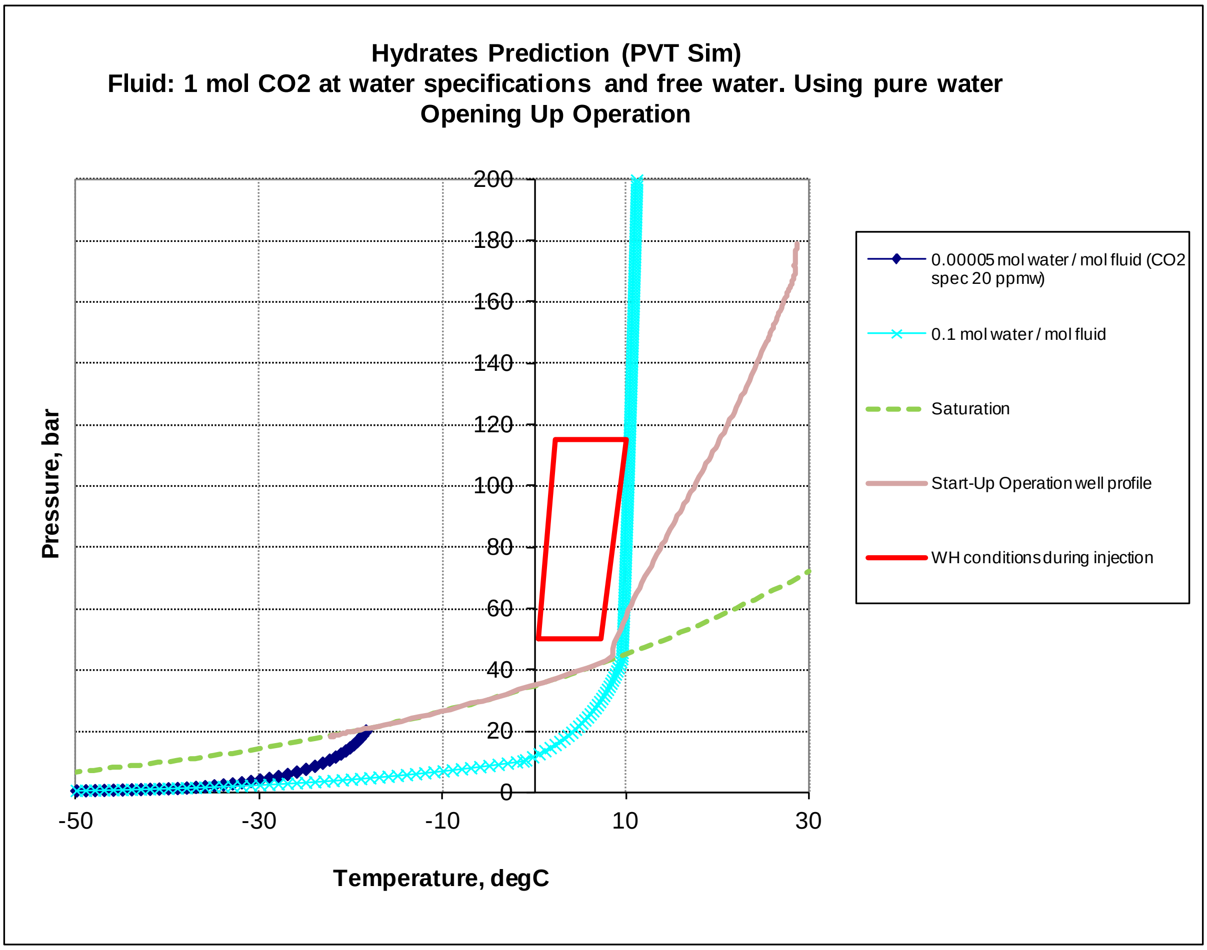


Figure 3-17: Hydrate equilibrium curve and well conditions during start-up operations

The main risk during a well start-up operation is the hydrate deposition in the tubing and not in the formation. The top of the well during the start-up operation will be in the hydrate region with a low reservoir pressure. Expansion of the CO_2 over the wellhead choke will result in low temperatures for a period of time. The wellhead temperature of the steady state injection CO_2 will be approximately 0.5°C -10.1°C, which is well to the left of the hydrate equilibrium curve considering the presence of free water.

In the case that water is added to the well (e.g. well intervention) or suspected to be in the well (e.g. initial injection conditions) then hydrate inhibitor should be used before starting-up the well.

First CO_2 injection into the well

Water will be present during the very first injection of the well, either from the completion fluid or from the aquifer water. CO_2 has not been introduced in the well but there is the potential of having hydrocarbon gas in the wellbore (and possibly in the tubing).

The well will be at geothermal conditions limiting any hydrocarbon hydrate at the reservoir level. Due to the cold injection of CO_2 the well would be at the CO_2 or hydrocarbon hydrate region, Figure 3-18. As such, initial hydrate inhibition will be required during this operation.

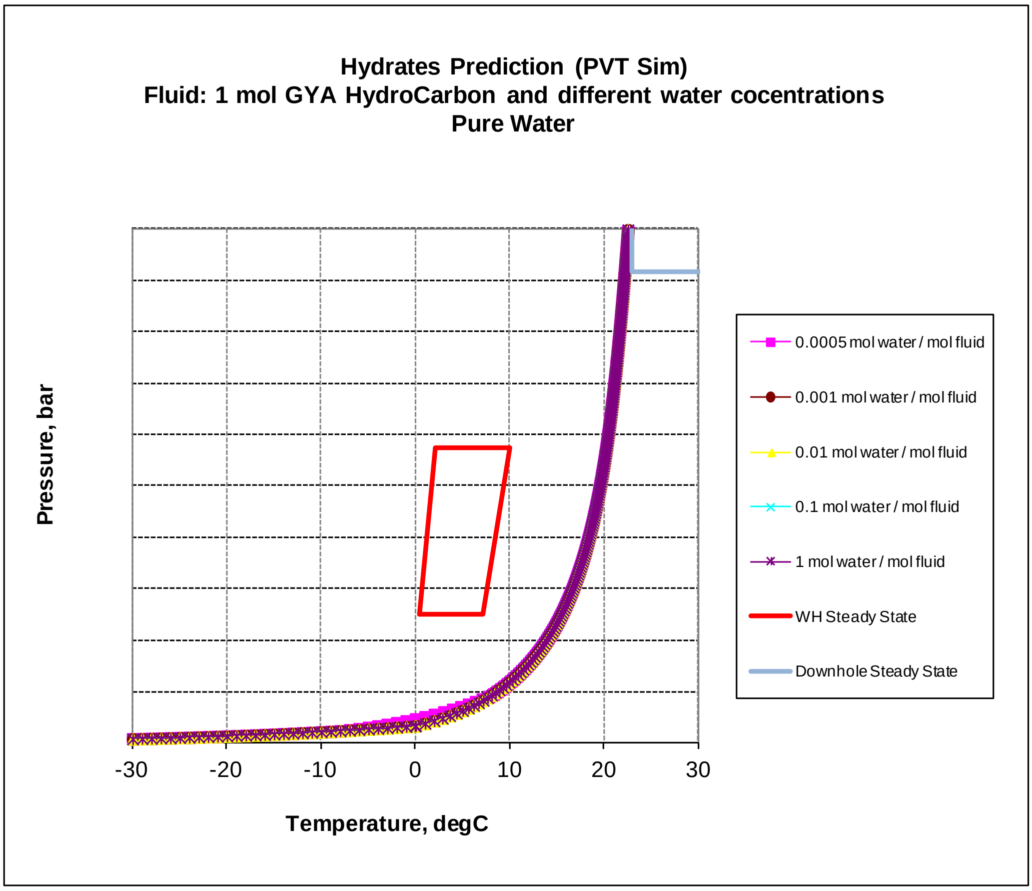


Figure 3-18: Hydrate equilibrium curve and well conditions during first start of injection (well filled with water)

Uncertainty in hydrate predictions

The pressure and temperature conditions of the CO_2 are in the region of forming hydrate problems in the presence of free water in the top of the well. However, there are some factors affecting the hydrate deposition which can minimise the effect of the hydrates, as follows:

- Formation of hydrates is not an instantaneous process. It requires time. Agglomeration of hydrates also requires time. Hydrates can be formed but it might not create a flow blockage (Dendy Sloan, 2000).
- Water is heavier than even dense phase CO_2 at the Goldeneye conditions. Free water will tend to accumulate in the bottom of the well where temperatures are higher and outside of the hydrate deposition temperature. However, there is uncertainty in the water column in the wells.
- The formation temperature conditions will always be above the CO_2 hydrate equilibrium temperature, as such there is not a risk of damaging the injectivity of the well for hydrates. The main issue is in the top of the well in the presence of free water.

3.2.4.3 Hydrate Inhibition Strategy

From the previous discussions, the cooling of the injection well induced by the injection of CO_2 will have the potential to create conditions favourable for the formation of hydrates, which means a hydrate mitigation strategy is required.

Continuous hydrate inhibition is not required under normal injection because of the specification of the CO_2 stream regarding water content.

The recommendation is to displace hydrate inhibitor in the well when the well is closed-in as a batch injection. The inhibitor should be displaced between the Xmas tree and the SSSV installed in the well during the closed-in time. Batch hydrate inhibition will feature as an instruction in the well operational procedures that will be developed for the injection system.

The placement of the SSSV should consider the hydrate deposition for CO_2 and hydrocarbon gas.

This strategy will be reviewed during FEED.

3.2.4.4 Hydrate inhibitor selection

The liquid chemical hydrate inhibitor employed for inhibition of hydrates will be either methanol or a mixture of Mono Ethyl Glycol (MEG) and water. Methanol is currently preferred hydrate inhibitor over MEG based upon:

- MEG (normally mixed water) has a higher viscosity than methanol
- The CO_2 will tend to remove the water from the MEG/water system making the MEG system even stickier and more prompt to create formation damage
- Difficult to break down any alcohol in comparison to MEG (MEG to be pumped is a mixture of water/MEG)
- Deep-water wells experience – Methanol is normally used to combat hydrates
- Methanol is compatible with the materials of the tubing (even in the presence of CO_2)

Sleipner wells in Norway use methanol injection. The well has a SSSV and an injection sub for methanol injection between the Xmas tree and the SSSV. The wellhead and Xmas tree is of standard offshore layout with provision for methanol injection through the upper blocks cross (Baklid, 1996).

Snohvit field in Norway presented injectivity issues at the beginning of the project, believed to be caused by Halite. A recipe of regular water with Methyl Ethyl Glycol (MEG) was pumped in the well in a weekly basis until the problem was overcome (Hansen, 2013). No formation damage has been reported for the Tauben formation; however the well was a cased and perforated well with a high permeability than the Captain formation limiting the formation damage created by the MEG mixture.

3.2.4.5 Required volumes and pressures

The SSSV depth is currently planned to be installed at around 2550ft [777m] (hydrate deposition is one of the selection criteria of the SSSV depth). 6.1m^3 of methanol is required for the batch displacement of methanol between the SSSV and the Xmas tree considering a 4½" [114mm] tubing.

The available pressure of the methanol system at the wellhead is estimated at 225bara which allows for methanol displacement in the well when the well is even filled with hydrocarbon gas.

3.2.5 Joule Thomson cooling upon CO_2 injection into the reservoir

A Joule Thomson cooling effect can be expected when CO_2 undergoes adiabatic expansion upon entering the formation. The likelihood of encountering CO_2 expansion problems in Goldeneye is very low, due to the low JT coefficient based upon the injection pressure and temperature. Cooling for Joule Thomson effects of less than 3°C is anticipated, due to the relatively high pressure of the reservoir.

The injection conditions in Goldeneye: relatively high reservoir pressure, small delta pressure between the well and the reservoir and low injection temperature are adequate to avoid cooling of the CO_2 due to CO_2 expansion. This is demonstrated below:

Table 3-1: Joule Thomson expansion calculation near wellbore for different injection conditions.

Reservoir Pressure	Injection Temperature, °C	JT coefficient, °C/bara	Delta Temperature for 500psia (34.5bara) expansion, °C
2650psia	23	0.029159	-1.0
182.7bara	35	0.050492	-1.7
3450psia	23	0.016643	-0.6
237.9bara	35	0.030261	-1.0

A delta pressure of 500psia [34.5bar] was used as a worst case scenario in terms of JT effects on temperature across the wellbore. Reference case is in the order of 280-380psia [19.3-26.2bara].

3.2.6 Halite Precipitation

Halite investigation for Goldeneye was reported in (UKCCS-KT-S7.19-Shell-001 Wells Fluid Flow Assurance & Technical Design, 2010) and summarised in this report. More data from Snohvit has become available in recent years and is included in this analysis. (UKCCS-KT-S7.19-Shell-001 - Wells Fluid Assurance & Technical Design, 2010).

This problem has been observed in salt-saturated formation water reservoirs, and is caused by water evaporation around the wellbore due to CO_2 injection. The formation water in Goldeneye has a relatively low salinity (56000ppm TDS) that which will minimise the effect of any potential salt precipitation.

CO_2 injection can lead to desiccation of the near wellbore of the injector due to the slight solubility of water into the CO_2-rich phase if the injection stream is dry. When a large number of pore volumes of dry CO_2 have been in contact with the water (i.e. close to the injector) all water will have evaporated. Since the salt dissolved in the water is not soluble in the CO_2 stream it will stay behind and (upon complete dry-out) deposit as solid salt. In theory this can lead to a reduction of absolute permeability in the near-wellbore zone, and might lead to a reduction in injectivity. A straightforward calculation and comparison to operational CCS projects, presented in the next two paragraphs, shows that for Goldeneye the risk of injectivity reduction due to this dry-out effect is minimal.

The Goldeneye water chemistry has a TDS concentration of around 56,000mg/l. The Goldeneye water is NaCl dominated brine (Na plus Cl concentration is 52,000mg/l). Even with full deposition of salt in situ the total salt deposited is only 56 gram for every litre of formation water, almost completely as halite (solid NaCl). Since the specific gravity of halite is 2.17g/cc this corresponds to 26cc of solids for every litre of formation water. Even if the pore space would be completely filled by formation water (i.e. 100% water saturation) this would lead to a relative porosity reduction of only 26/1,000. Given the average porosity of 25% in the main reservoir sands (Captain D) this would reduce porosity from 25% to 24.4%.

It should be noted that around most injectors the water saturation is likely to be lower, for two reasons:

Initial water saturation in Goldeneye is only approx. 13% on average going down to 7% around crestal wells. During the production phase this will have increased for some of the wells when watering out, but at least the crestal wells will only have partially watered out at the end of production.

Even for a fully watered out well, the initial water saturation upon injection is only (1-residual gas saturation). Moreover, as has been shown in core flood experiments and modelling studies, dry-out only starts to become significant after some of this water has been displaced by injected CO_2. The water saturation at the start of significant dry-out depends on the relative permeabilities, but especially for a high permeability sandstone like in Goldeneye will be close to residual which for such a sandstone is approx. 10-20%.

Therefore the relative porosity reduction is only [0.07-0.20]*26/1,000 = [2-5]/1,000, and therefore the porosity only reduces from 25% to [24.88-24.96]%. This is a very small reduction. Even if much of the salt deposition would occur in the pore throats (which have a relatively large diameter in Captain D due to its high permeability) it is not expected to have a measurable effect on permeability and therefore injectivity is expected to be unaffected by the build-up of the dry-out zone.

From field experience perspective, CO_2 injection is ongoing in Sleipner in Norway and in Salah, Algeria. These operations have a similar or higher likelihood than Goldeneye to exhibit injectivity decline due to the build-up of a dry-out zone. This is for two reasons:

- These fields have a similar (Sleipner) or higher (in Salah) value of the product (salinity * water saturation), primarily due to a similar or higher initial water saturation at start of dry-out, and therefore a similar or higher amount of salt is available for deposition (per unit pore volume).
- These fields have similar (Sleipner) or much lower (in Salah) permeability and therefore (even for the same amount of salt deposition per unit of pore volume) similar or higher risk of deposition in the pore throats leading to permeability reduction.

However, no injectivity decline (besides decline due re-pressurisation of the formation) has been reported for these operations during their injection period since start-up (14 and 6 years, respectively). Therefore for Goldeneye the risk of injectivity impairment due to salt deposition in the dry-out zone consider to be low.

Snohvit field in Norway presented injectivity issues at the beginning of the project. It was reported (Hansen, 2013) that rapid increase in injection pressure during the initial stages of the project was interpreted to be caused by halite precipitation in near the wellbore. A recipe of regular water with MEG was pumped into the well on a weekly basis until the problem was overcome. Further communication with Statoil clarified that the problem was attributed to the salt precipitation possibly due to a high salinity (~150000 ppm TDS) and the presence of multiple perforation intervals presented in the well. Production Logging (PLT) indicated cross-flow between the perforations at well closed-in conditions. This facilitated water replenishing and further salt precipitation by water dehydration with further CO_2 injection then leaving more salt in the near wellbore area which lead to injectivity deterioration. The water and MEG treatment possibly re-dissolve the salt present in the wellbore.

In the case of halite precipitation bullheading of water can be applied in the wells to re-dissolve the salt present in the well. Platform modifications to pump water into the wells are not justified due to the low risk of having injectivity issues. Well intervention can be carried out in case of observing this problem in the wells.

3.2.7 Near Wellbore Asphaltene Deposition

High levels of carbon dioxide are known to destabilise asphaltene dispersions in hydrocarbons. As the composition of the hydrocarbon present in the CCS injection wells is assumed to be the same as that produced from the reservoir, it is assumed that the total quantity of asphaltenes present in the gas hydrocarbon on a percentage volume basis is zero. Therefore the risk of depositing asphaltenes that could lead to injectivity impairment is nil.

The Oil Rim present initially in Goldeneye is expected to be smeared out by the gas production and aquifer encroachment into the reservoir. The likelihood of having asphaltenes from the oil rim deposited in the CO_2 injector wellbore is very low due to the small amount of oil from the liquid hydrocarbon produced in Goldeneye being reported. The wells were completed in the top of the Captain D and structure away from the original position of the oil rim.

3.2.8 Near Wellbore Wax deposition

Injecting cold CO_2 in a reservoir containing hydrocarbons has the potential to condense the heavier alkene fractions leading to wax deposition. However, on review of the Goldeneye gas / condensate composition it is clear that the amount of heavy end hydrocarbons is very small. Furthermore, previous laboratory testing has shown that the cloud point of the Goldeneye condensate could not be reached at -2.2°C and that the calculated cloud point of the condensate was predicted to be -6°C. As the temperature of the near wellbore is not predicted to get below 20°C during CO_2 injection, even assuming no heat transfer from the formation, the likelihood of wax deposition is nil.

3.3 Matrix or Fracturing conditions

Stress regime calculations in combination with the expected injection pressures indicate that the initial phase of injection (for low reservoir pressure) will be under matrix injection. However, the late phase of injection (as the reservoir pressure increases) is hugely uncertain in terms of injection condition (matrix or fracturing conditions). The main uncertainty in the calculations is the reduction in minimum stress caused by the temperature contrast between the reservoir temperature and the bottom hole injection temperature.

The reservoir has experienced a depletion process during the hydrocarbon production phase, from the original pressure of around 3830psia [264.1bara] to 2100psia [144.8bara] at the end of the hydrocarbon production phase. The minimum horizontal stress is affected by this process. The reservoir will undergo a pressure increase process during the closed-in period, provided by the aquifer support and later by both the CO_2 injection and the aquifer support. The minimum stress development is again uncertain during a re-pressurisation process, where it might not recover from the absolute minimum in an inelastic process to the original minimum stress in a full elastic process. The CO_2 will be injected cold with an average difference of ~60°C between the formation temperature and the injection temperature. The minimum stress will also be affected by the cooling effect and there is an important uncertainty in the exact value of this reduction.

Considering the minimum stress range in the formation including all the factors (depletion, re-pressurisation and thermal effects) and the required injection pressure, the most likely scenario during the initial injection period, when the reservoir pressure is relatively low, is to have injection under matrix conditions. However, as the reservoir pressure increases and hence the injection pressure increases, it is possible that the reservoir may be fractured during the injection process. There is uncertainty in terms of the pressure at which the injection will move from matrix to fracturing injection.

Injection under fracturing conditions can propagate fractures in the Captain formation. These fractures in the reservoir are not detrimental to the containment capacity of the seal (Rodby/Hidra).

3.4 Injection under fracturing conditions

The objectives of this section are (i) to estimate the fracture length in the Captain sandstone which can be created in the formation in the case of injecting under fracturing conditions and (ii) highlight the sealing capacity of the Rodby under fracturing injection of the Captain D. It is not intended to demonstrate the primary seal capacity for all possible scenarios.

3.4.1 Software

The estimated length of the fracture in the case of injecting under fracturing conditions is calculated using a Shell Proprietary software called PWRI-Frac.

The PWRI-Frac tool computes fracture dimensions, well injectivities, and flood front displacements for injection above frac pressure. The software does not predict the starting point of the frac or breakdown of the formation.

For injection of CO_2 above frac pressure, the fracture propagation process is entirely steered by fluid leak-off into the formation.

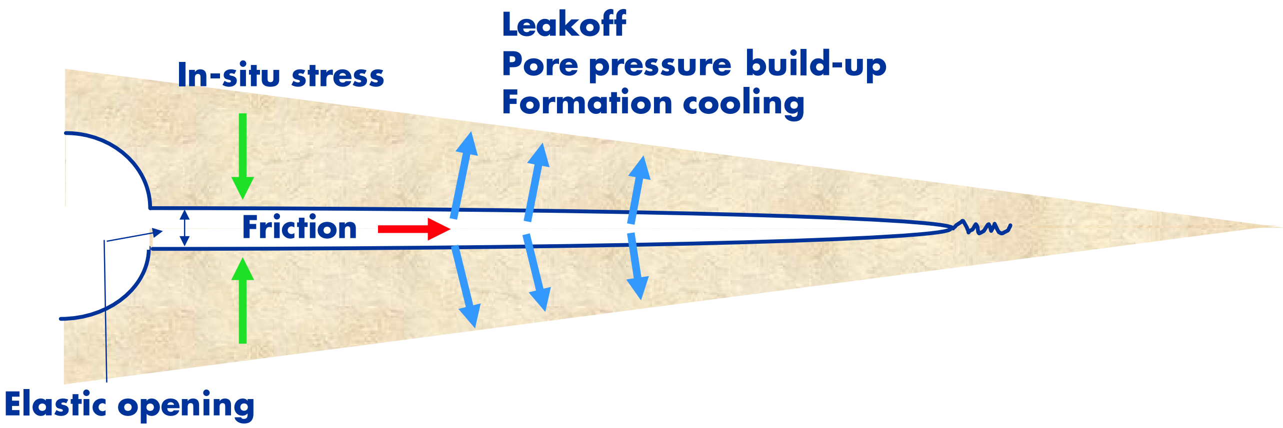


Figure 3-19: Fracture propagation mechanism in PWRI

The purpose of the program PWRI-Frac is to provide (i) an estimate of lateral and vertical extension of induced fractures, (ii) of vertical fracture (non-)confinement and (iii) hydraulic requirements during injection.

The software was developed for water injection purposes. The input has been modified to suit the CO_2 injection (viscosity, thermal properties, etc.).

3.4.2 Model Input

The main reservoir is the Captain D. The Rodby shale is the main seal above the Captain formation. There is a substantial marl formation above the Rodby called Hidra. The Plenus Marl is not present in all the Goldeneye producing wells. The Rodby formation is a shale directly above the Captain formation with an average thickness of 180ft [55m] TV. The Hidra marl has an average thickness of 225ft [38m] TV.

Injection characteristics as follows:

- Injection surface temperature: 4°C
- Injection bottom hole temperature: 23°C
- CO_2 viscosity at reservoir temperature: 0.05 cP
- CO_2 viscosity at injection temperature: 0.15 cP
- Heat capacity CO_2: 2400 kJ/kg/°C
- CO_2 Density: 940 kg/m^3 average @ injection conditions

Injection rate: 52 MMscfd for 7.5 years.

52 MMscfd (114 tonnes/h, 1mtpa) is the average between the design rate of the CCP and the minimum rate of the CCP (65% of the maximum). The downhole rate equivalent is 2950 m^3/d (927 kg/m^3 density of CO_2 for 3200psia [221bara] and 25°C).

Sensitivity is done for the maximum rate of the CCP 138.4 tonnes, h, 63 MMscfd equivalent to 3580 m^3/d downhole and the minimum rate of 89.9 tonnes/h, 41 MMscfd; equivalent to 2320 m^3/d downhole.

7.5 years is used in the calculations considering that a well can be injecting maximum for ~ 75% of the duration of the project (10 million tonnes).

Solids loading: 11 ppm vol

This value accounts for small particles and corrosion products injected into the formation. Solids are to be removed at the platform level to prevent impairment near the wellbore. The current specified level is that particles more than 5 micron should be removed from the injection system. This will reduce the amount of solids injected into the wells.

The fact that the CO_2 will be dehydrated will ensure that no corrosion is caused in the offshore pipeline.

Reference case is for 0.1 pounds solids per thousand barrel CO_2 at downhole conditions equivalent to ~ 11 ppm vol. This value is considered high considering the nature of the CO_2 and the filtration at the platform. This value was selected in order to have conservative estimates of fracture length.

Sensitivities will be done with practically no solids (0.5 ppm Vol) and 22 ppm vol.

The following data were used for this study in terms of rock characteristics:

Table 3-2: Base assumptions for the fracture modelling [1ft = 0.3048m, 1psia = 0.06895bara]

	Captain D	Unit	Remarks
Top	8,300	ftTV	Average depth of Captain D
Bottom	8,480	ftTV	180ft average thickness of Captain D

Porosity	0.25	Fraction	Average of the wells in Captain D
Permeability	790	mD	Average of the wells in Captain D Sensitivity for 500 and 1500 mD
Pore Pressure Captain	2,100 2,650 3,450	psia	Lowest after depletion Before CO_2 injection At the end of injection
Reservoir Temp.	83	°C	
Fracture initiation	8,330	ftTV	Assumed. Wells completed in 60-70 ft TV of Captain D. Sensitivity for top of Captain D 8,301ft
Young's Modulus Captain D	16.2 12-20	GPa	Reference case of 16.2 GPa is based on Geomechanics report (average injection test) 12 GPa: Based on lab analysis. Geomechanics report Table 4.5. Average load test 20 GPa. Based on lab analysis. Geomechanics report Table 4.5. Maximum recorded under injection conditions.
Poisson's Ratio Captain D	0.26	-	Lab analysis. Geomechanics report Table 4.5 on injection. Sensitivity to 0.15 based on lab analysis - depletion
Poro-elastic constant Captain D	0.6	-	Delta minimum stress / Delta reservoir pressure. Reference case in the area of Goldeneye. Variation from 0.4 to 0.8
Coefficient Thermal Expansion	9.2	1/°C	1 E -05 Recent lab analysis and literature information
Rodby Formation	7 0.38 5 / 0.1	GPa	Young Modulus Poisson's Ratio (Geomechanics report, Table 4-3) Porosity (%)/ Permeability (mD) Hydrostatic (formation not drained)
IB Shales below CaptainD	6 0.35 5 / 0.1	GPa	Young Modulus Poisson's Ratio (Geomechanics report, Table 4-3) Porosity (%)/ Permeability (mD) Hydrostatic (formation not drained)

The formation stresses are discussed in the following section.

3.4.3 Stress Regime

The stress regime under CCS for the Captain D will depend on the original in-situ stress conditions (section 3.4.3.1), which are affected by changes in stress due to the depletion (section 3.4.3.2), and later due to the pressure increase process (section 3.4.3.3). The minimum stress is also affected by the injection of cold fluid into the reservoir (section 3.4.3.4).

3.4.3.1 Original Stress

The values presented in this section have been documented in the (PCCS-05-PT-ZP-9025-00004 Geomechanics Report, 2014)

An estimate of the vertical stress is calculated by integrating the density logs of these wells. The vertical stress or Maximum Stress has been estimated at 23.3kPa/m [1psia/ft, 233mbar/m].

The original formation stresses in the Captain reservoir are not accurately known. No fracture tests or formation leak-off tests were performed in the reservoir before the hydrocarbon production.

In well 14/29a-3 a Formation Limit Test was carried out at 7986.2ft [2428.7m] TVSS at the Hidra formation. The Hidra marl formation was tested to an equivalent gradient of 0.572 psia/ft [129.4mbara/m]. This is much lower than the anticipated gradient from regional stress trend maps and it is due to the nature of the test (not an extended leak-off test)

An estimated value for the minimum horizontal stress (Sh) has been obtained from regional stress trend maps of the Central Graben North Sea area. It is assumed that the test was stopped before formation breakdown had occurred. The formation strength at the Rodby and Hidra levels are expected to be around 0.72 to 0.80 psia/ft [162.9 to 181mbara/m]

The reference case minimum stress at the top of the Rodby is estimated at 6186psia [426.5bara] at 8140ft [2481m] TVD. Low and High values are estimated based on regional stress information

Table 3-3: Minimum horizontal stress at the Rodby formation [1psia/ft = 226.2mbara/m, 1 psia = 0.06895bara]

Minimum Stress Gradient, psia/ft	Sh (psia) @ top Rodby (8140ft TVD)	Remarks
0.76	6186	Reference case. Average between the minimum and maximum recorded
0.72 Low	5861	Lowest recorded gradient in the region
0.80 High	6512	Highest recorded gradient in the region

The original Captain D minimum stress is estimated to be 5993psia [413bara] at 8300ft [2530m] TVD, based on 0.72 psia/ft [162.9mbara/m], typical of North Sea sandstones where the minimum stress gradient in the sandstone shows an average of 95% value of the shales above.

Gradient, psia/ft	Sh (psia) @ top Captain (8300 ft TVD)	Remarks
0.72	5993	Reference case. Average between the minimum and maximum recorded
0.68 Low	5677	Lowest recorded gradient in the region
0.76 High	6308	Highest recorded gradient in the region

Table 3-4: Original minimum stress at the Captain formation [1psia/ft = 226.2mbara/m, 1 psia = 0.06895bara]

The reference case minimum stress at original conditions is represented in the Figure 3-20. The stress contrast in the reference case between the bottom of the Rodby and the top of the Captain is estimated at around 300 psia [20.7bara].

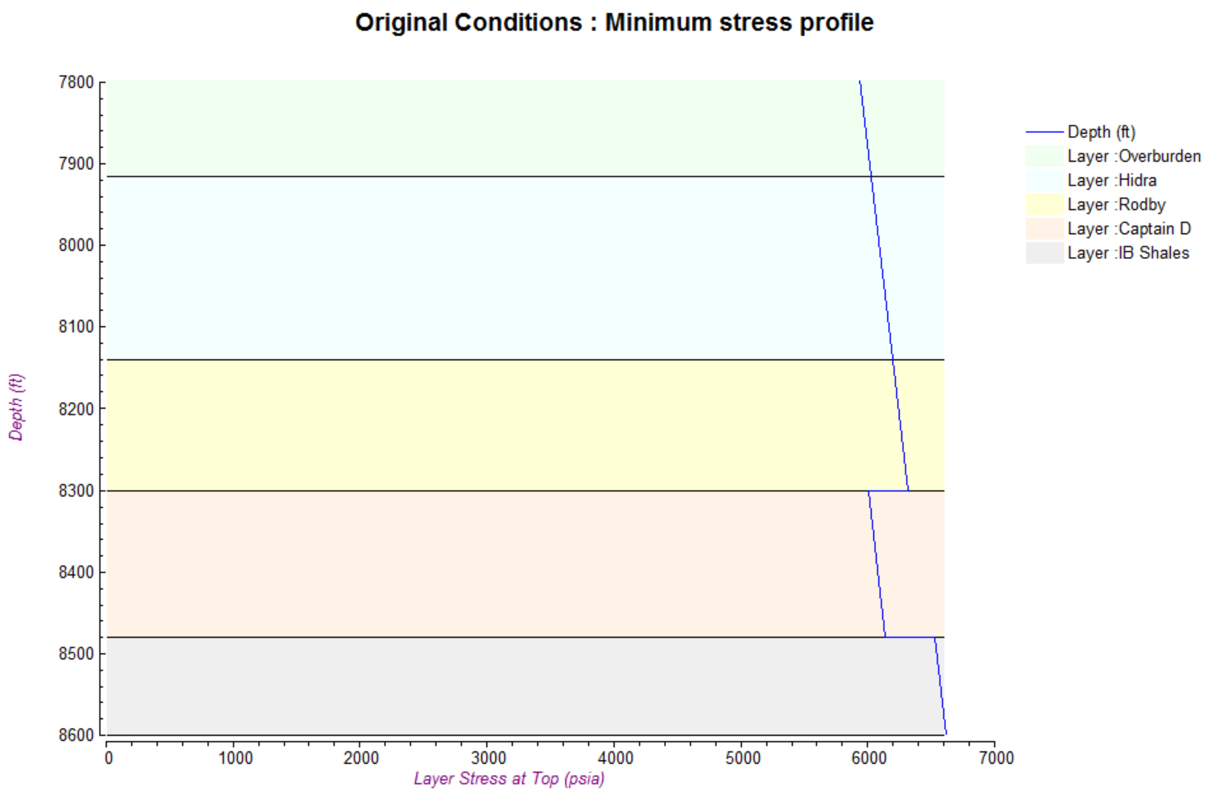


Figure 3-20: Original minimum stress conditions at isothermal conditions

3.4.3.2 Change in Stress due to depletion

The minimum stresses in the reservoir in Goldeneye are reduced with respect to the original stress due to depletion by the hydrocarbon production.

Assuming linear elastic behaviour, the reduction will depend on the Poisson's Ratio of the rock and the change in pressure. Compression of the sand grains by pore pressure needs to be included in the calculations resulting in the depletion constant.

The minimum horizontal stress in a depleted reservoir is estimated using the depletion constant or poro-elastic constant as follows:

$$\Delta S_h = Ap * \Delta Ppore$$

Where Ap = depletion constant or poro-elastic constant (-)

$\Delta Ppore$ is the depletion level (psia)

For soft rocks (like Captain D in Goldeneye) the expected poro-elastic constant is in the order of 0.55-0.70. A base value of 0.6 has been used in the calculations with sensitivities to 0.4 and 0.8 ((PCCS-05-PT-ZP-9025-00004 Geomechanics Report, 2014). The following Table 3-5 illustrates the change in minimum horizontal stress with change in reservoir pressure at different poro-elastic constants for depletion scenarios under an isothermal scenario.

Table 3-5: Change of minimum stress in the Captain formation due to depletion (during the hydrocarbon production phase) [1 psia = 0.06895bara]

P reservoir	Depletion Level	Change in Sh, psia due to depletion 0.6 Depletion Constant (reference case)	Change in Sh, psia due to depletion 0.4 Depletion Constant	Change in Sh, psia due to depletion 0.8 Depletion Constant
3830	0	0	0	0
3450	380	-228	-152	-304
3050	950	-570	-380	-760
2650	1180	-708	-472	-944
2100 (lowest reservoir pressure, psia)	1730	-1038	-692	-1384

3.4.3.3 Inflation process – Reservoir pressure recovery (aquifer strength and CO_2 injection)

The reservoir pressure has increased from the lowest on depletion 2100psia [145bara] to the current 2620psia [181bara] (December 2013). The pressure will continue increasing to around 2650psia [183bara] before injection to 3450psia [238bara] after CO_2 injection.

One uncertainty is the ability of the formation to increase or recover the minimum horizontal stress with the pressure inflation when the formation has previously been through a depletion phase. Data suggest that some formations will not fully recover the minimum horizontal stress as calculated using the poro-elastic constant.

The reference case for minimum stress recovery is estimated at 50% of the depletion constant. Ranges vary from 0% recovery to 100%.

The 100% recovery indicates a totally elastic behaviour of the rock; the minimum stress recovery is based on the depletion constant.

A 0% recovery in the minimum stress min indicates a totally inelastic behaviour where despite of the pressure recovery the minimum stress will not recover from the minimum stress estimated at the lowest reservoir pressure.

The change in minimum stress due to the inflation process is included in the Table 3-6.

Table 3-6: Change of minimum stress in the Captain formation due to pressure increase (during the pre-CO_2 injection and CO_2 injection periods) [1 psia = 0.06895bara]

P reservoir (psia)	Inflation Level, Change in reservoir pressure from lowest after depletion, psia	Change in Sh, psia due to inflation (after depletion) 50% recovery and 0.6 Depletion Constant (reference case)	Change in Sh, psia due to inflation (after depletion) 100% recovery and 0.6 Depletion Constant	Change in Sh, psia due to inflation (after depletion) 0% recovery
2100 (min P reservoir)	0	0	0	0
2650	550	+165	+330	0
3050	950	+285	+570	0
3450	1350	+405	+810	0

3.4.3.4 Cooling effect on minimum stress

Temperature has a comparable effect on the in-situ stresses as pore pressure. Fracture propagation pressure is reduced if the injected fluid is colder than the surrounding formation. The cold fluid causes the formation to shrink or contract, resulting in a reduced formation stress and lower fracture pressure.

The reduction in fracture pressure as a function of the temperature difference between formation and injection fluid can be determined using the following equations:

$$A_T = \alpha * \frac{E}{1-\nu}$$

where:

A_T = Thermo-elastic constant (bara/°C)

E = Young's Modulus (GPa)

α = coefficient of linear thermal expansion (1/°C)

ν = Poisson's Ration (-)

and

$$\Delta S_h = A_T * \Delta T$$

Where

ΔT = temperature differential (°C)

The typical coefficient of thermal expansion for sandstone is estimated at 10 E-6/°C (5.55 E-6 / °F). The CO_2 bottom hole temperature is estimated to be between 23°C to 35°C (section 4.3.10). As such, there will be a difference of around 113°F (60°C difference). This will reduce the minimum stress in the reference case in the order of 145bara [2000psia], Table 3-7.

Table 3-7: Change of minimum stress in the Captain formation due to thermal effects

	Young's Modulus, GPa	Poisson's Ratio	Thermo-elastic constant, bara/C	Change in Sh with 60° C difference, bara/psia
Reference Case	16.2	0.26	2.3	-131/-1905
Small change	12	0.15	1.41	-85 / -1228
High change	20	0.26	2.7	-162 / -2351

3.4.4 Injection conditions (matrix or fracturing) – The numbers

Injection under fracturing conditions will occur when the injection pressure is above the minimum stress. The minimum stress in the reservoir is affected by the depletion phase, the current and the future pressure increase in the reservoir and the cooling effect as described in the previous sections of this report. The main uncertainty lies in the reduction of the minimum stress due to the cooling effects which is affected by the geomechanical properties of the rock.

The reference case minimum stress in the formation is calculated as follows:

Table 3-8: Summary of change in minimum stress in the Captain formation - reference case [1 psia = 0.06895bara]

Reservoir Pressure	Original Sh, psia	DSh, psia depletion (0.6 depletion factor @ P minimum)	DSh, psia inflation (50% recovery	Isothermal Sh (after depletion, inflation), psia	DSh due to 60°C cooling	Sh after depletion, inflation and cooling (60°C), psia
2100psia (maximum depletion)	5993	-1038	0	5993	N/A	N/A
2650psia (beg.of inj.)	5993	-1038	+165	5120	-1905	3215
3050psia (mid Inj.)	5993	-1038	+285	5240	-1905	3335
3450psia end of inj.)	5993	-1038	+405	5360	-1905	3455

The comparison of the bottomhole injection pressure and the minimum stress during injection will determine the type of injection: under matrix conditions or fracturing conditions.

The bottom hole injection pressure during the CO_2 injection would be between 280psia [19.3bara] and 380psia [26.2bara] above the reservoir pressure depending on the well. This indicates that the initial conditions of injection (reference case) will be under matrix conditions and switching to fracturing conditions with time (increase in reservoir pressure). However, the exact conditions of when this will occur are uncertain given the uncertainty in the calculations.

The main factor affecting the injection under matrix and fracturing conditions is the level of cooling of the reservoir. Under isothermal conditions the injection would be under matrix conditions during the duration of the project. Equally and assuming a low effect on the minimum stress given by the formation cooling then the injection condition will be under matrix condition. However, considering the high value in the thermo-elastic constant then the injection would be under fracturing conditions.

This is illustrated in the Figure 3-21 at the start of injection for different cooling effects and variables (stress gradient, depletion constant, and inflation recovery) on the minimum stress. As it can be observed the main factor affecting the minimum stress is the thermo elastic properties of the rock where the minimum stress changes dramatically (difference between the blue and green lines). Depending on its value the injection might occur under injection conditions (Minimum stress to be lower than the bottom hole injection pressure for injection under fracturing conditions).

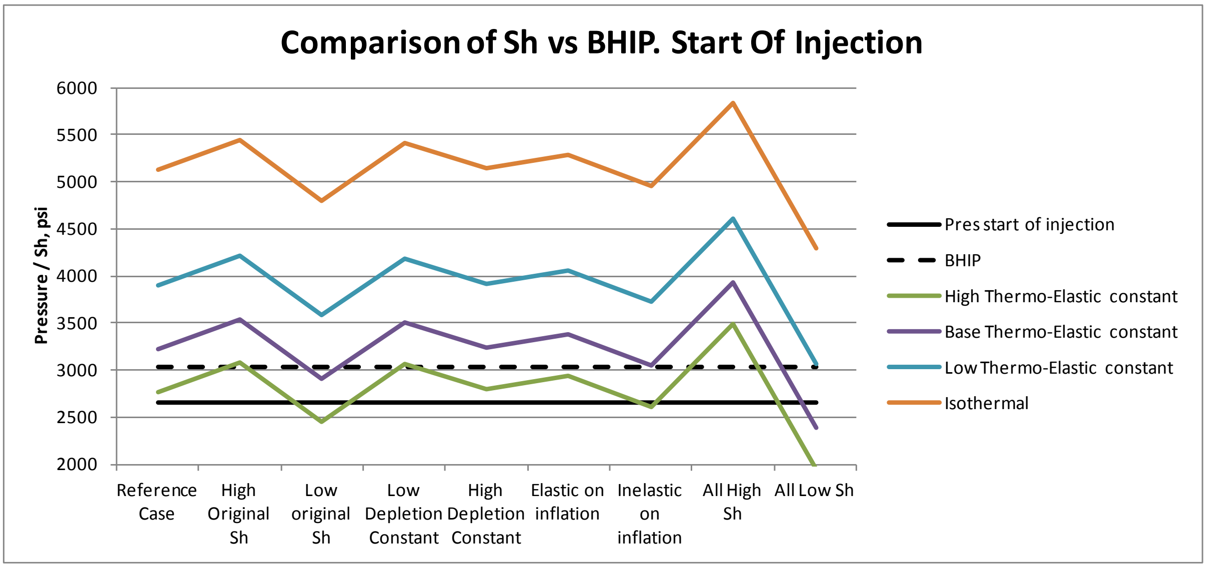


Figure 3-21: Uncertainty in minimum stress in the Captain formation and injection conditions at the start of injection. [1 psia = 0.06895bara]

Injection under fracturing conditions cannot be assumed to happen during the duration of the project due to the uncertainty in terms of the effect of injection temperature in terms of minimum stress. Matrix conditions should be used for the design of the injection system in terms of suspended solids. However, injection under fracturing conditions in terms of fracture containment and potential issues in the lower completion should be investigated due to the possibility of having this kind of injection.

3.4.5 Summary of cases investigated for propagating fracture under injection

Injection under fracturing injection cannot be ruled out; as such, the extension of the propagating fracture needs to be investigated. The following cases have been investigated, **Table 3-9**.

Table 3-9: Considered PWRI cases for simulation

Section	Case	Objective
3.4.7	Base Case	Considers the reference case stress at the mid-point reservoir pressure in the project as discussed in section 3.4.6 and reference parameters in rock properties and injection conditions (section 3.4.2)
3.4.8	Injection rate sensitivity	Evaluate the minimum and maximum rate of the capture plant
3.4.9	CO_2 quality sensitivity	CO_2 with minimum solids content and a high value (worst case in terms of containment)
3.4.10	Reservoir Properties	Variation in reservoir permeability and mechanical properties in the reservoir
3.4.11	Fracture initiation point	Evaluate a fracture initiation as close as possible to the primary seal
3.4.12	Original Stress conditions	Worst case in terms of stress contrast between the primary seal and the reservoir

3.4.6 PWRI. Base case pressure and minimum stress

The base case involves the following scenario:

- Reservoir pressure of 3,050psia [210bara]. Average reservoir pressure during the CO_2 injection. Rodby and Hidra formations are undepleted /undrained, **Figure 3-32**.
- The isothermal minimum stress of the Captain is 5,240psia [361bara] for 3,050psia reservoir pressure. This is used as the stress value related to the base case minimum stress for the depletion and inflation process. The stress contrast between the bottom of the Rodby and the top of the Captain is around 1,070psia [74bara] after the depletion and pressure recovery mechanism in the reservoir, Figure 3-23.

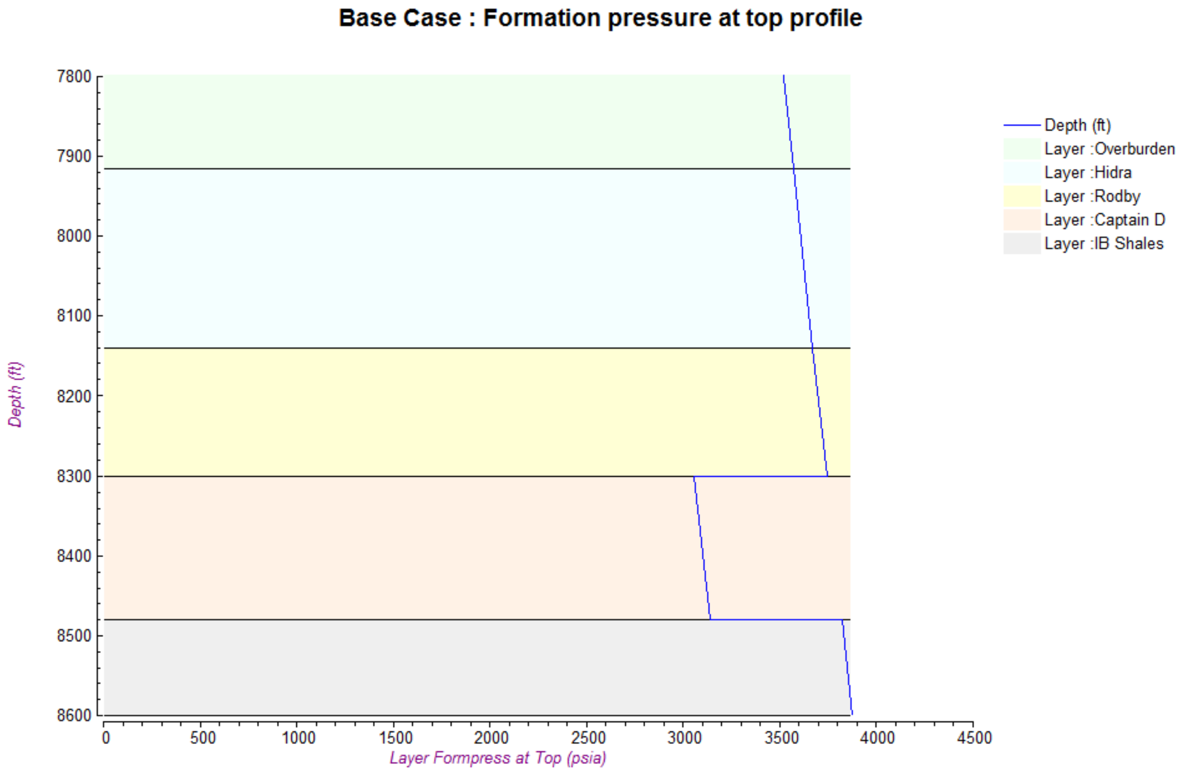


Figure 3-22: Formation pressure in the Goldeneye area (pressure in the Captain formation as an average pressure over the life of the project)

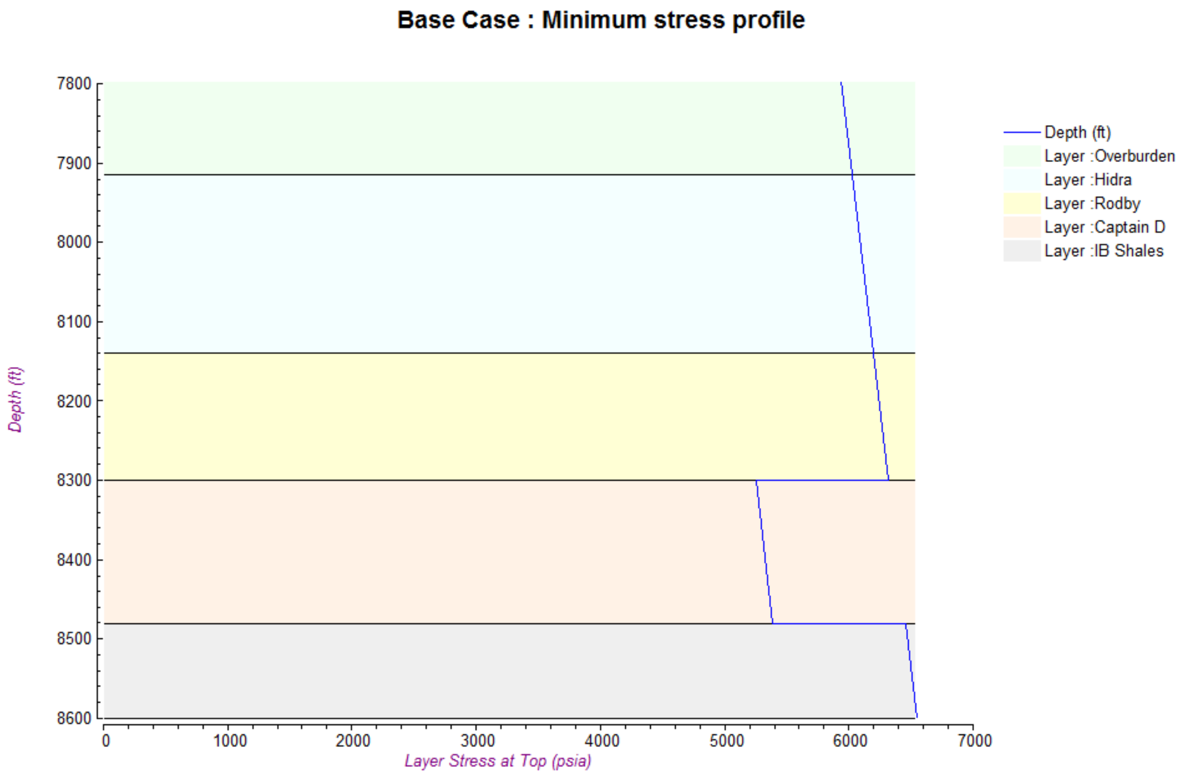


Figure 3-23: Isothermal minimum stress in the Goldeneye area for injection (reference case Captain minimum stress)

3.4.7 Fracture Geometry. Base Case Simulation results

The results of the simulation (**Figure 3-24**, **Figure 3-25**and Figure 3-26) indicate that the fracture will preferentially grow down toward the bottom of the Captain D reservoir. The fracture will initially grow towards the top of the Captain reservoir. The fracture will grow ~20ft [6m] into the Rodby formation at the end of the injection period. The main reason for this is the stress contrast and the differences in properties between the Rodby seal and the Captain D formation. The fracture will have a length of approximately 130ft [39.6m].

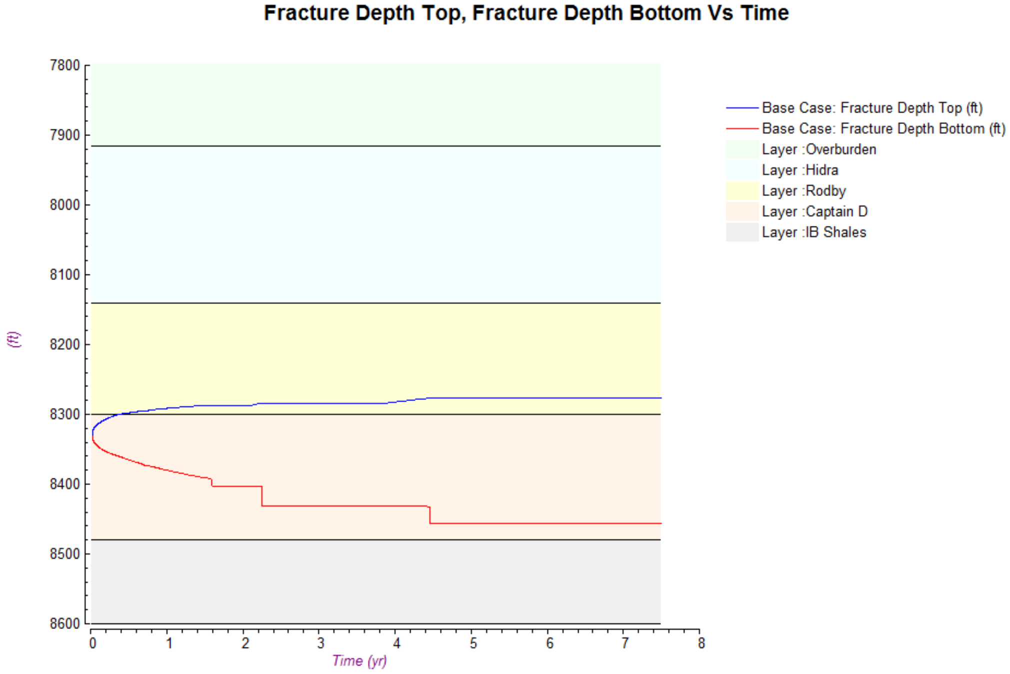


Figure 3-24: Base case. Fracture depth to and depth bottom with time

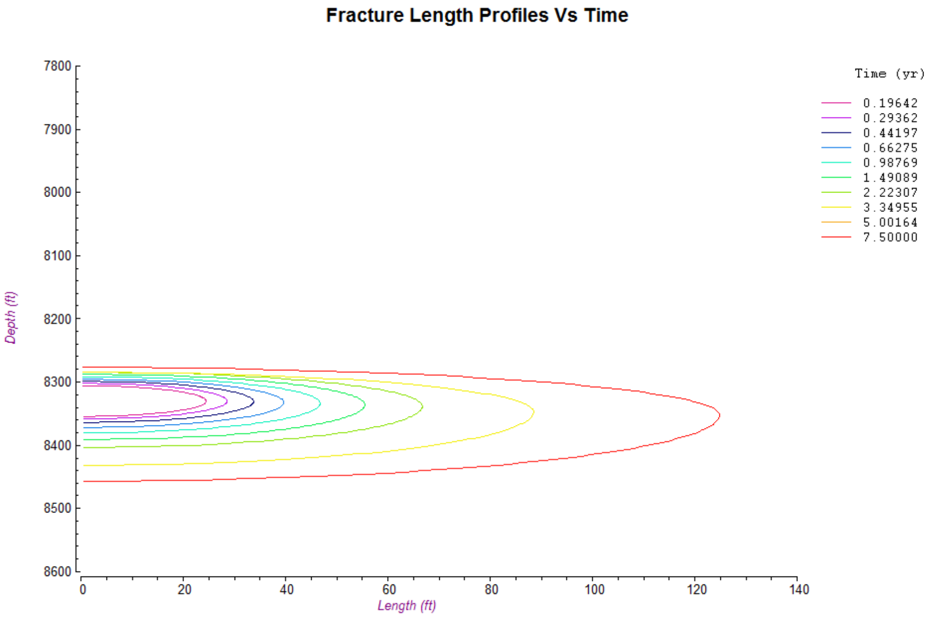


Figure 3-25: Base case. Fracture length profile with time

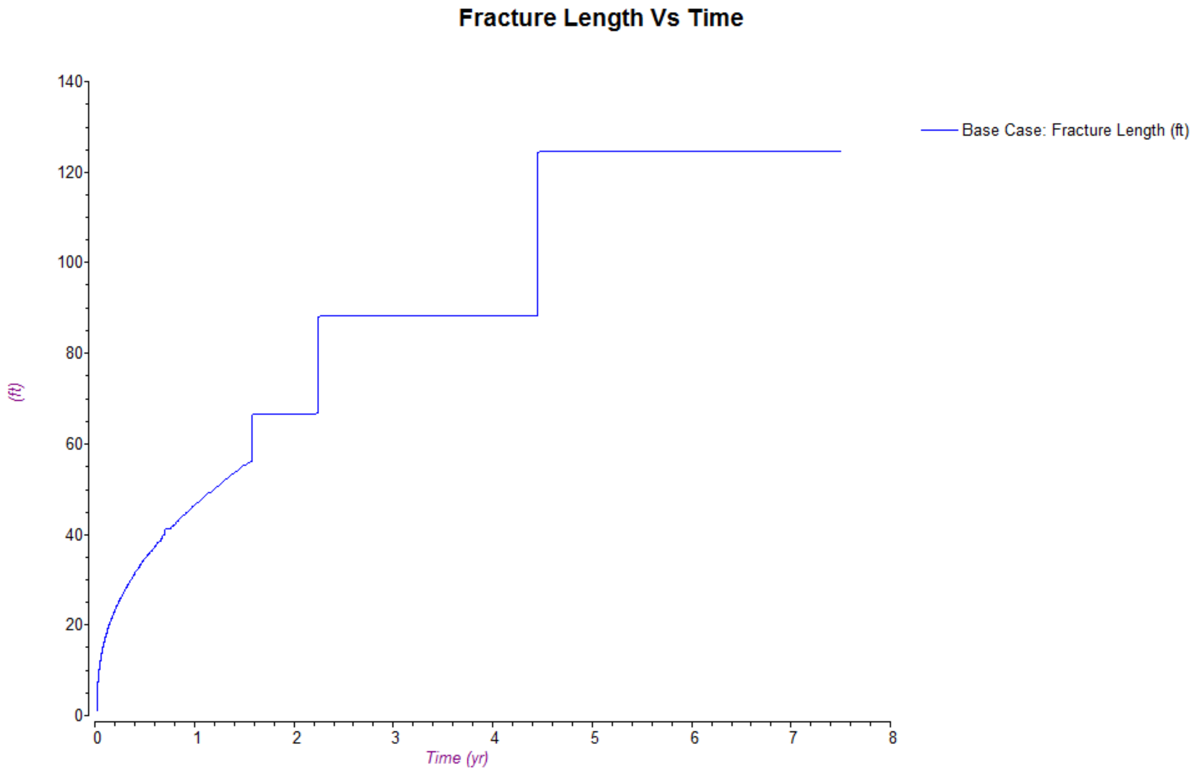


Figure 3-26: Base case. Fracture length with time

(The Figures above show sudden changes to the fracture geometry. This is an artefact of the output from the simulation).

3.4.8 Fracture Geometry. Injection rate sensitivity

Sensitivity has been considered with 2,320m^3/d and 3,580m^3/d downhole CO_2 injection equivalent to 41 MMscfd (89.9 tonnes/h) and 63 MMscfd (138.3 tonnes/h) respectively. The base case is for 2,950 m^3/d downhole equivalent to 52 MMscfd.

The results (Figure 3-27 and Figure 3-28) are similar to the base case in terms of fracture growing to the bottom part of the Captain D. The length of the fracture is very similar, being slightly longer (150ft) for the high injection rate case.

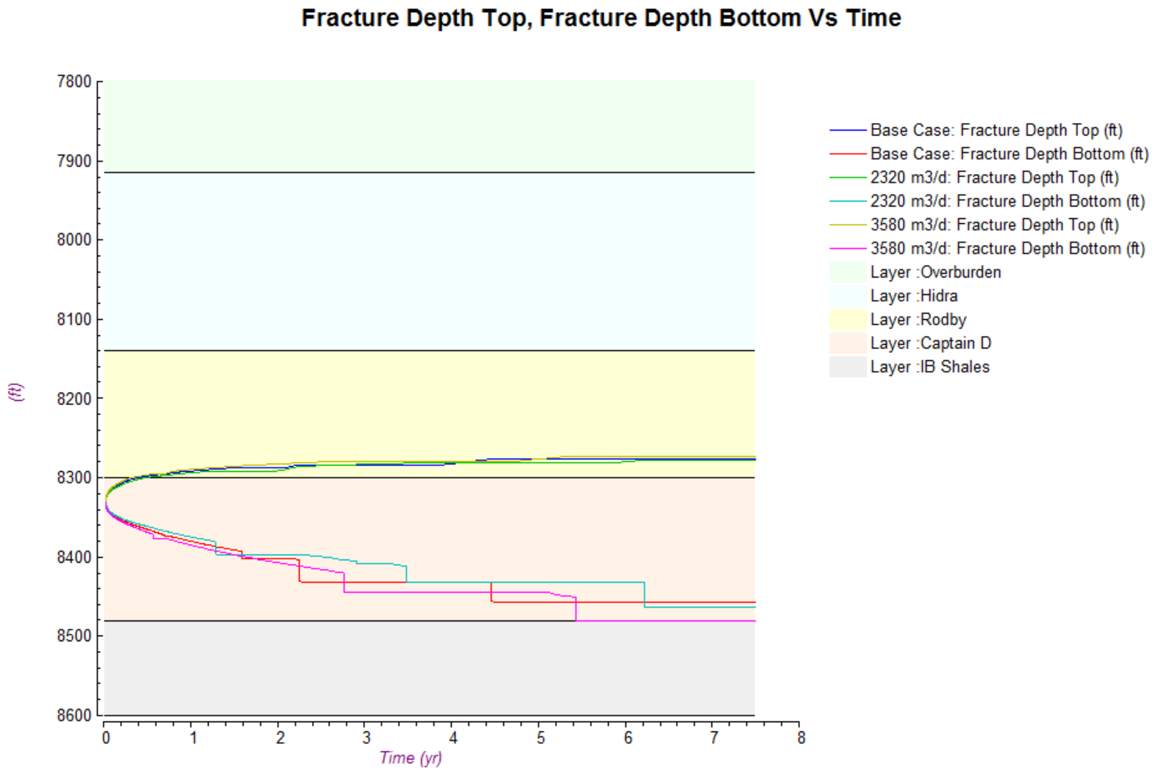


Figure 3-27: Rate sensitivity. Fracture depth to and depth bottom with time

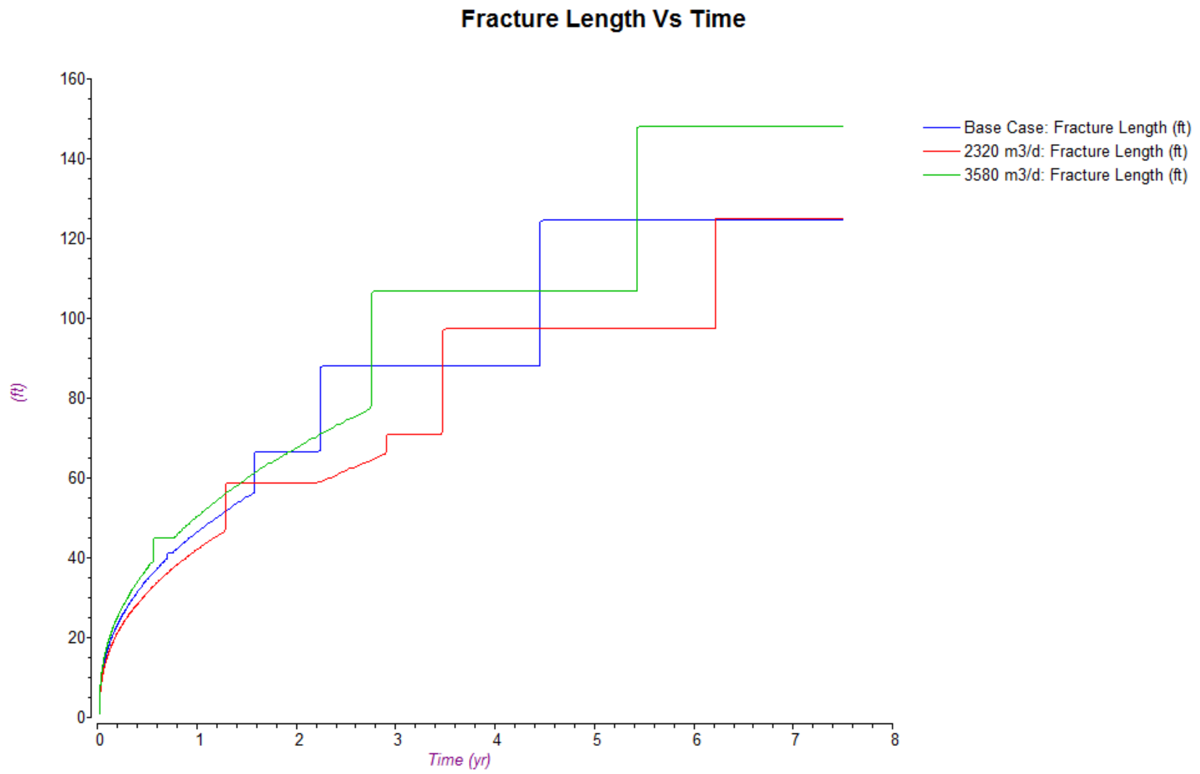


Figure 3-28: Rate sensitivity. Fracture length with time

3.4.9 Fracture Geometry. CO_2 quality sensitivity

Sensitivities have been considered for different solids content in the CO_2. The quality of the CO_2 is estimated to be good as particles of less than 5 microns will be removed from the system to avoid lower completion and formation blocking. This will reduce the amount of solids injected into the wells. However, the value is uncertain but it is considered very low as the dehydrated CO_2 will not generate corrosion in the offshore pipeline.

Reference case for modelling purposes was selected for 0.1 pounds solids per thousand barrel CO_2 at downhole conditions equivalent to ~ 11 ppm vol. This reference case for modelling has been selected as a very conservative number in terms of solids content in the CO_2 which will give an extended geometry of the fracture. Sensitivities will be considered/tested with practically no solids (0.5 ppm Vol) and 22 ppm vol. The first one is the lost likely scenario in terms of CO_2 quality due to the filtration requirement at the platform.

The results of the simulation (Figure 3-29 and Figure 3-29) show that a high solids concentration (22ppmvol) will allow for the fracture to grow longer (250ft) at the end of injection. Furthermore the fracture will grow faster to the bottom of the Captain formation. The fracture will be contained by the Rodby formation.

The results show that under a low solids content (0.5 ppm vol) the fracture will be of small dimensions with a fracture length of only 25ft [7.6m]. The fracture will grow slowly into the top of the Captain and it will not reach the bottom of the Captain at the end of the injection period.

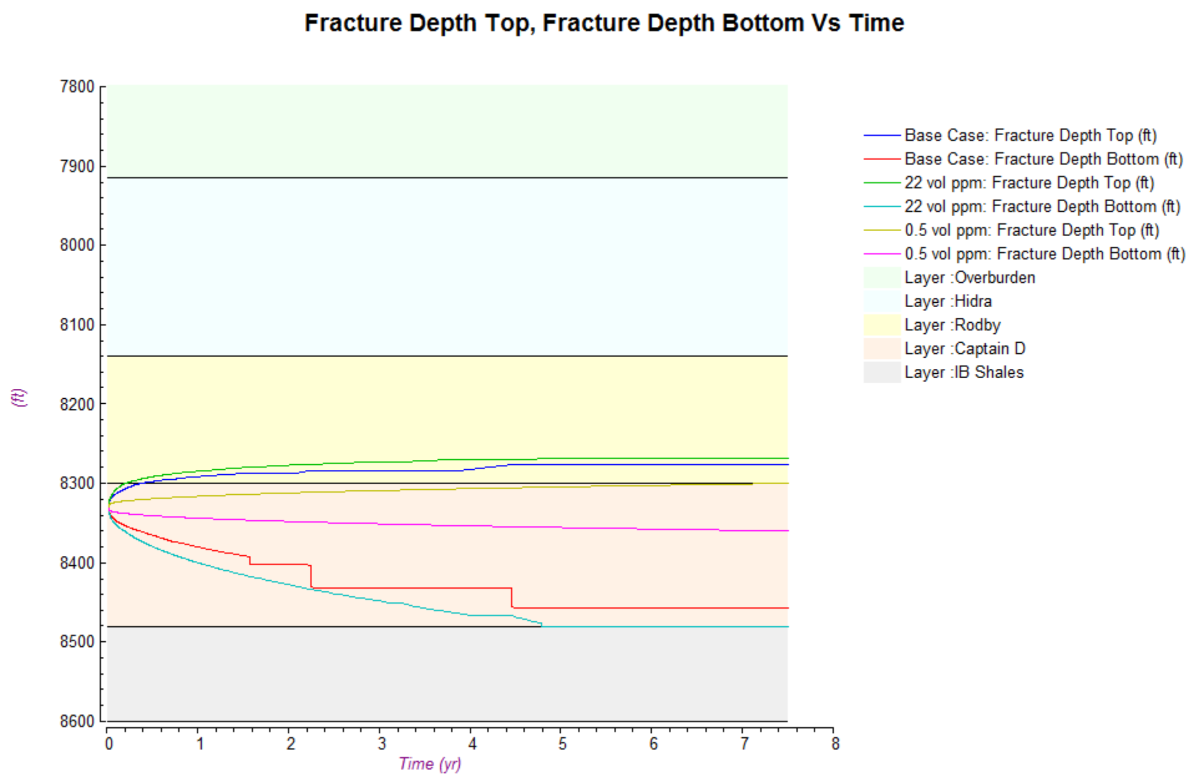


Figure 3-29: CO_2 quality sensitivity. Fracture depth to and depth bottom with time

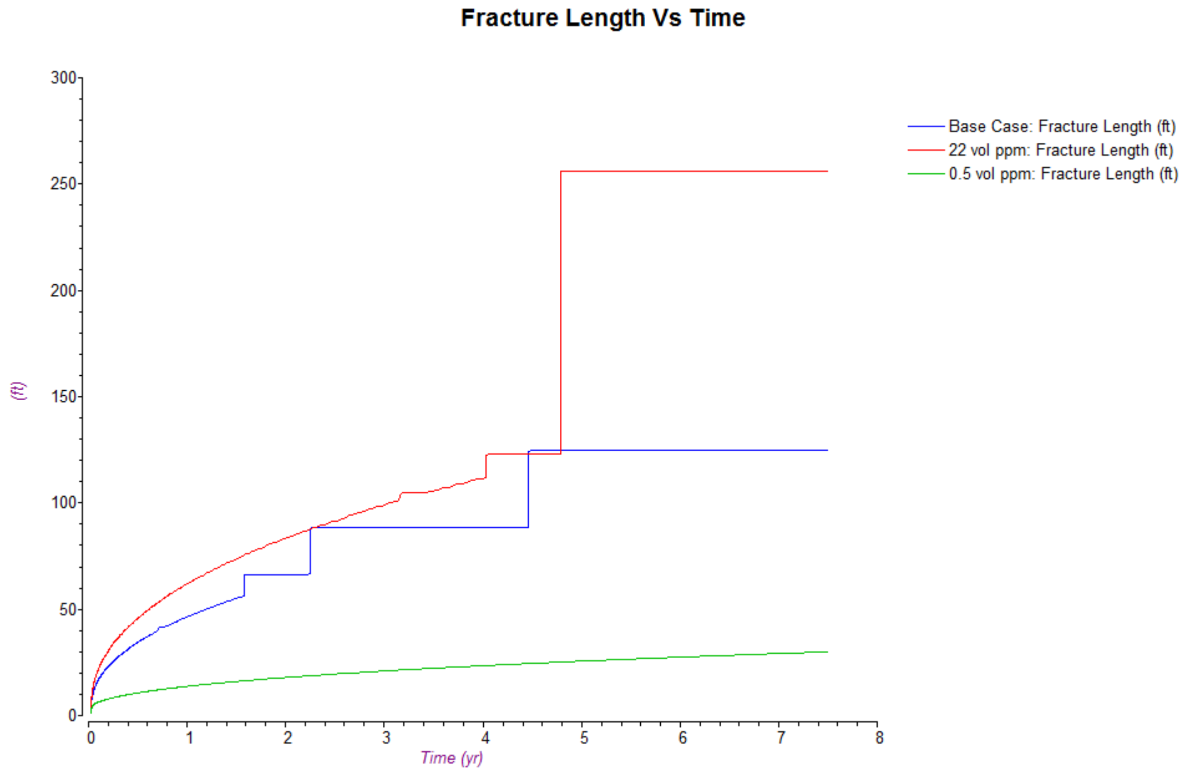


Figure 3-30: CO_2 quality sensitivity. Fracture length with time

3.4.10 Fracture Geometry. Reservoir Properties sensitivities

Reservoir Properties sensitivities were performed in terms of Permeability, Porosity, Young's Modulus and Poisson Ratio to evaluate the fracture length and containment in the Rodby, Table 3-10. For all the cases evaluated the created fracture was contained within the Rodby formation.

Table 3-10: Estimated fracture length for different reservoir sensitivities [1ft = 0.3048bara]

Sensitivity	Fracture length, ft
Base Case	130
Permeability = 500 mD	132
Permeability = 1500 mD	110
Young's Modulus = 12 GPa	130
Young's Modulus = 20 GPa	150
Poisson Ratio = 0.15	135

3.4.11 Fracture Geometry. Fracture Initiation Point

The base case fracture initiation point is 30ft [9m] below the top of the Captain formation. A sensitivity analysis is carried out to evaluate the containment of the fracture assuming that the fracture is initiated 1ft from the top of the Captain, as near as possible to the Rodby formation seal.
The results (**Figure 3-31**) show that the fracture is contained within the Rodby. The fracture length increases to 190ft [58m].

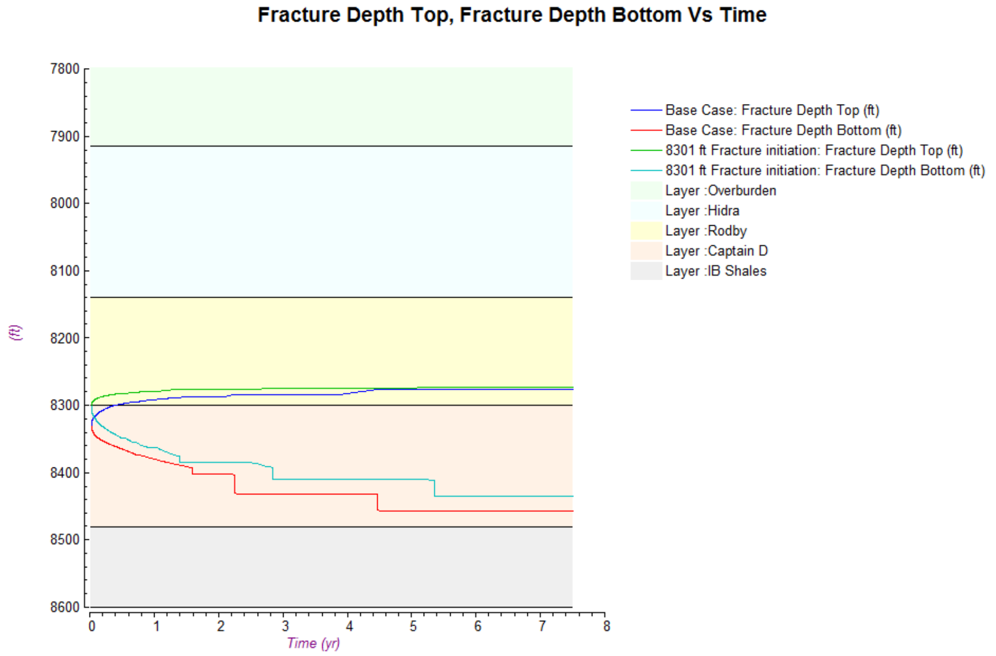


Figure 3-31: Fracture geometry with time for different fracture initiation points

3.4.12 Fracture Geometry. Original Stress conditions

This simulation considered the original conditions in reservoir. This is considered the worst conditions in terms of fracture containment as per the stress contrast between the bottom of the Rodby and the Captain reservoir is at its minimum (300psia [21bara] only).

The simulations results (**Figure 3-32**) show than even under this hypothetical scenario the fracture will remain within the Rodby formation.

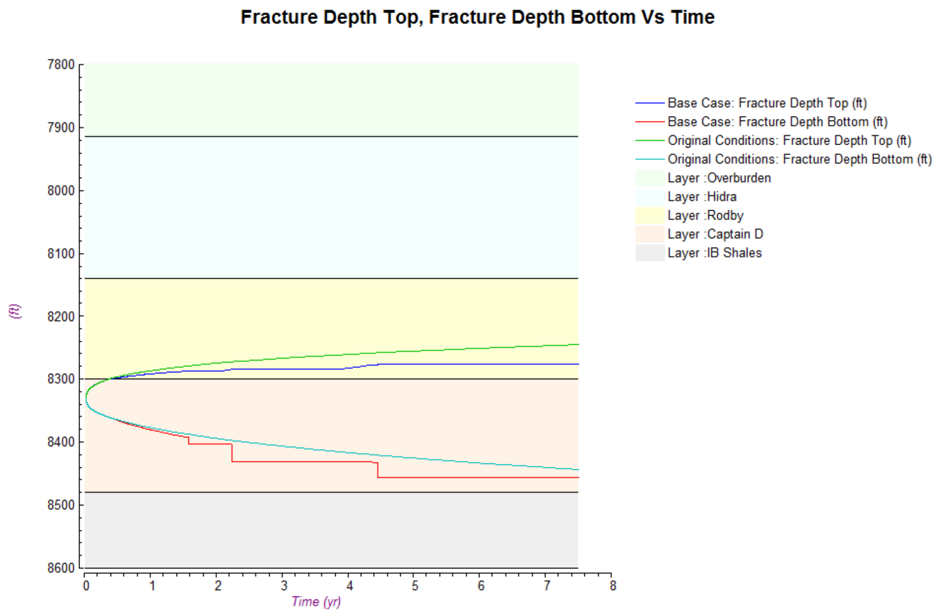


Figure 3-32: Fracture geometry with time assuming no changes in original minimum stress (worst case for fracture containment)

3.4.13 Summary of fracture geometry calculations

Under any circumstance or cases the fracture will grow over the top of the Rodby formation even considering the worst case scenario for stress contrast (original conditions – section 3.4.12). The fracture length will depend on different variables, the most important being the solids content into the injected CO_2. In the case of a limited amount of solids case (as expected from the project as filtration is included) the fracture will grow slowly to the top of the Captain D and will not reach the bottom of it.

3.5 Mitigation Options Summary for injectivity management

As described in the previous section, there are a number of different proactive activities that will be carried out to minimise the risk of not being able to inject the required amount of CO_2. Proactive measures are summarised in section 3.5.1; there are also reactive options which might be available should injectivity issues be encountered, and these are outlined in 3.5.2. Injectivity management of the risk in Section 3.5.3.

3.5.1 Summary of proactive measures

The following actions have been identified as proactive mitigation options to reduce the risk of poor injectivity.

- Pipeline cleaning

  The pipeline needs to be cleaned before the CO_2 injection this will form part of the pipeline decommissioning

- CO_2 filtration

  Filtration will be required on the platform to the adequate levels of solids size to avoid lower completion plugging and erosion and formation plugging. The current estimated size is 5 microns.

- Chemical injection

  Batch injection of hydrate inhibitor to avoid hydrate precipitation. This can be stopped once the formation water is displaced from the wellbore as the hydrates forming ingredients will have been removed.

- Number of wells

  Additional well(s) or redundant injectors will be converted to CO_2 injection to increase flexibility in terms of integrity and / or injectivity issues. This well can be used as a continuous injector in case of finding injectivity problems.

3.5.2 Reactive measures

Apart from the proactive mitigations options described above, there are potential remedial activities which can be executed in case of observing problems:

- Well stimulation

  Using the proper fluid and operation depending on the damage mechanism. For example water stimulation for halite precipitation. It can be carried out with a stimulation boat given the space limitation on the platform or by simple bullheading into the wells.

- Flow back

  Major operation for cleaning clogged solids on the screens. This might be applicable in case of having problems with the pipeline coating disbondment. The planned platform configuration will not allow a flow of the CO_2 hydrocarbons mixture into the process facilities. Most likely a well test package will be required.

- Others

  Consideration should be given to new technologies in case of having injectivity problems. This can be related to ultrasonic tools, heaters, etc.

- Side-track

  It is always the last resort to restore injectivity. New formation is drilled with the formation damage issues.

3.5.3 Injectivity Management summary

Initial injectivity problems are thought to be unlikely given the conditions of the storage formation. As described in the previous two sections there are proactive and reactive activities in order to ensure injectivity during the life cycle of the project.

The following summary presents the summary with the residual risk after applying mitigation measures. This overall picture is summarised in the following table:

Table 3-11: Injectivity management. Risk reduction

Stage	Mechanism	Description	Risk probability before mitigation	Mitigation Options	Risk probability after mitigation
Initial Injectivity	Reservoir Parameters	High absolute permeability based on core and production information.	Zero	-	Zero
	Initial Skin	High initial skin but stable drawdown during production.	VL	-	VL
	Fluid Change - PVT	Different PVT properties from the current HC production to the CO2 injection.	VL	Injectivity calculation considering the change of fluids	VL
	Relative Permeability	Short term effect. Minor effect on injectivity in the long term.	VL	Simulation scenarios (Longannet report)	VL
Injectivity deterioration with time	Fines Re-accommodation	Flow reversing will re-accommodate the fines embedded in the gravel pack (during the production phase) against the formation	L	Production conditions assessment	VL
	Desbonding Pipeline Coating	Potential for epoxy disbonding of the offshore pipeline	VL	Proactive: Filtration. Reactive - Flowback Sidetrack	VL
	Gravel Pack / Formation plugging	Plugging of the lower completion with particles. Sensitivity to big particles.	H	Filtration to the required levels Pipeline cleaning Reactive - Remedial activities - Stimulation	L
	CO2 expansion (JT effect)	Formation cooling due to JT effect.	VL	Reduced effect due CO2 bottomhole conditions	VL
	Halite	Water dry up due to CO2 injection. Salt precipitation	VL	Reactive - Remedial activities - Stimulation	VL
	Hydrates	Potential of Hydrate formation at the start of the injection due to hydrocarbon	M	Chemical inj. - Hydrate inhibitor	L

3.6 Injectivity test requirement

An injectivity test was considered to reduce some of the uncertainties in injectivity. However, given the value of information will not be significant and the complexity of the test is great, a decision has been taken not to proceed with this.

The current production phase of Goldeneye is the best indicator of the expected CO_2 injectivity in Goldeneye. It can be considered a long term injectivity test by hydrocarbon producibility.

The ideal injectivity test should be carried out with the same fluid and conditions expected during the operating phase of the injection, CO_2 for the case of CCS.

The length of any productivity / injectivity test should be tailored to the main uncertainties / risks considering the operational aspects of the test.

Another fluid (e.g. water, nitrogen, hydrocarbon) might be used, but the extrapolation of the results should be taken into consideration.

Doing the test with water, hydrocarbon or nitrogen will only have benefits in terms of reducing the uncertainty in terms of fines re-accommodation in the gravel pack.

In addition to the fines re-accommodation an injectivity test carried out with CO_2 will have small benefits with respect to the fluid change in terms of PVT, relative permeability and the risk of hydrates. The phenomenon related to fluid change is relatively well understood with a very low uncertainty. Reducing this further will not impact the project in terms of cost or decisions. There will be a reduction in Hydrates uncertainty from low to zero. However, the current thinking calls for batch hydrate inhibition.

The following Table presents the summary with the reduction of Risk / Uncertainty with respect to the current understanding of the injectivity in Goldeneye and the planned mitigation options. The table shows the value of the injectivity test over and above the current understanding.

Table 3-12: Injectivity test. Risk/Uncertainty comparison pre and post-test.

Stage	Factor	Current View (including planned mitigation)	Current risk uncertainty (includes planned mitigation)	Risk/Uncertainty after Injectivity Test		
				with CO2	with N2	with Water
Initial Injectivity	Reservoir Parameters	High absolute permeability based on core and production information.	Zero	Zero	Zero	Zero
	Initial Skin	High initial skin but stable draw down during production.	VL	VL No added value	VL No added value	VL No added value
	Fluid Change - PVT	Different PVT from the current HC production to the CO2 injection. Already included in the calculations	VL	0 Minor effect on injectivity based on different PVT. Easy to calculate	VL Another fluid introduced in the system.	VL Another fluid introduced in the system.
	Relative Permeability	Minor effect on injectivity in the long term. Scal analysis. Easy to calculate the difference Different scenarios with simialr results	VL	0 Information added in terms of permeability to CO2.	VL Complications with different injection fluids.	VL Complications with different injection fluids.
Injectivity deterioration with time	Fines Re-acommodation	Flow reversing will re-accommodate the fines embedded in the gravel pack (during the production phase) against the formation. Production conditions assessment indicate not a bn important effect	VL	VL Can give extra information in the short term	VL Can give extra information in the short term	VL Can give extra information in the short term
	Desbonding Pipeline Coating	Not expected. Filtration planned.	VL	VL Pipeline not used during the injectivity test	VL	VL
	Gravel Pack / Formation plugging	Plugging of the lower completion with particles. Sensitive to big particles. Filtration to required levels. Initial comissioning of the pipeline	L	L No added value. Injectivity test should be carried out with the particulates specification	L No added value. Injectivity test should be carried out with the particulates specification	L No added value. Injectivity test should be carried out with the particulates specification
	CO2 expansion (JT effect)	Formation cooling due to JT effect. Reduced effect due CO2 bottomhole conditions	VL	0 Information added in terms of temperature information	VL	VL
	Halite	Water dry up due to CO2 injection. Salt precipitation. Not expected	VL	VL No added value. It might be a medium time effect.	VL No added value	VL No added value.
	Hydrates	Potential of Hydrate formation in the lower part of the well at the start of the injection. Hydrate inhibitor proposed for the initial injection period	L	VL Cold CO2 to understand the risk of hydrates	L No added value	L No added value

For a CO_2 injection test and based on the current knowledge of Goldeneye wells, injecting CO_2 in the wells without carrying any modification to the well completion could jeopardise the integrity of the wells. This is related to the extremely low temperatures expected due to the Joule Thomson effect of the CO_2 and the related tubing shrinkage affecting the PBR in the well. Modifications in the well completion would need to be carried out prior to the injectivity test.

4 Vertical Lift Performance

This section details the vertical lift performance (temperature and pressure modelling of the upper completion) for the Goldeneye CCS wells. Given that CO_2 properties are very sensitive to Pressure and Temperature, it is necessary to accurately predict the change in properties with an equation of state. Heat exchange in the well and frictional pressure drop need to be accurately modelled.

Analyses have shown that injecting dense phase CO_2 into a depleted reservoir has the risk of producing low temperatures in the injection tubing.

4.1 CO_2 properties and its influence in well performance simulators

Most phenomena related to CO_2 dynamics become apparent with an understanding of the key fluid properties and their dependence on temperature and pressure.

The critical temperature of CO_2 is 31.1°C and the critical pressure is 73.8bara. At temperatures and pressure above this critical point, CO_2 exists as a supercritical fluid, whereby it has a density similar to a liquid but exhibits gas-like viscosity (Figure 4-1).

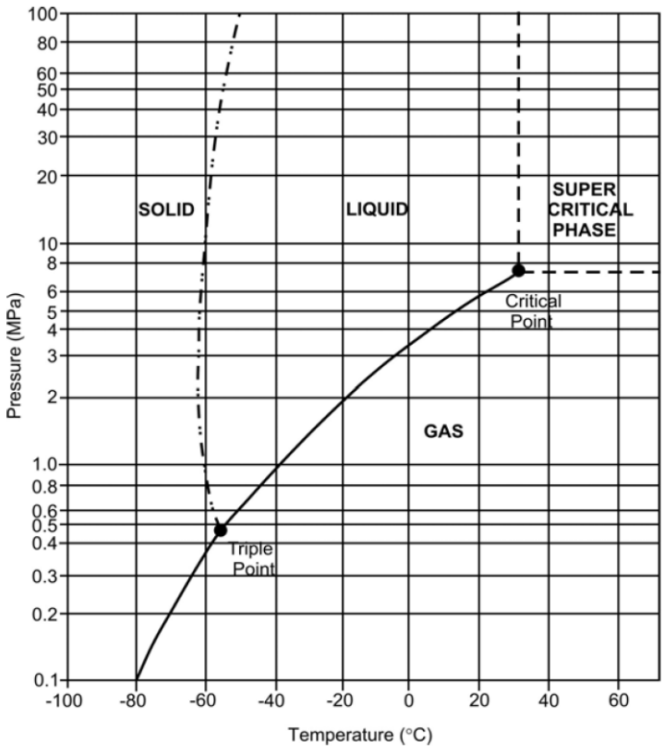


Figure 4-1: Phase diagram of CO_2 [from Wong, 2005]

The Figure 4.2 shows the variation of density as function of Pressure and Temperature for CO_2. Especially for pressures and temperatures that are often encountered in CO_2 injection, the CO_2 density changes significantly for only relatively small variations in pressure and/or temperature. The changes are more pronounced near the critical point conditions. The changes are less severe in the liquid and vapour areas.

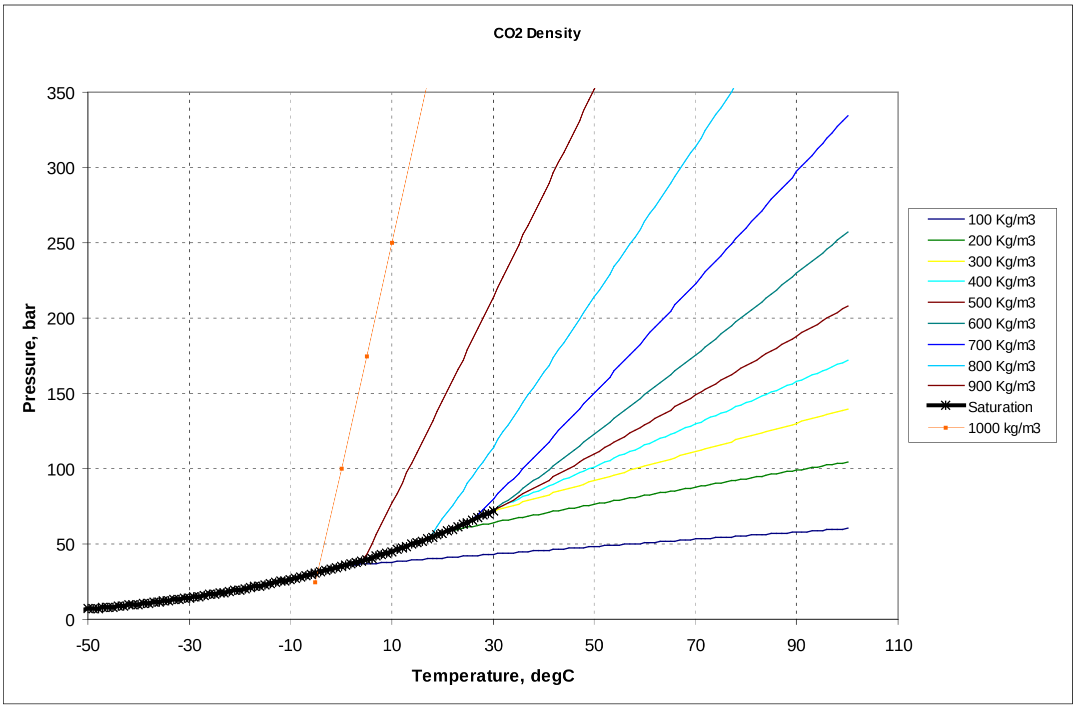


Figure 4-2: Variation of CO_2 density with pressure and temperature (NIST data)

The Figure 4-3 below shows the Joule Thomson coefficient of the CO_2 at different pressure and temperatures. The JT coefficient is very high (~9 to 14°C/Mpa or 0.9 to 1.4°C/bara) for the vapour phase whilst in the liquid phase the JT coefficient is low (0 to 1.5°C/Mpa 0 to 0.15°C/bara).

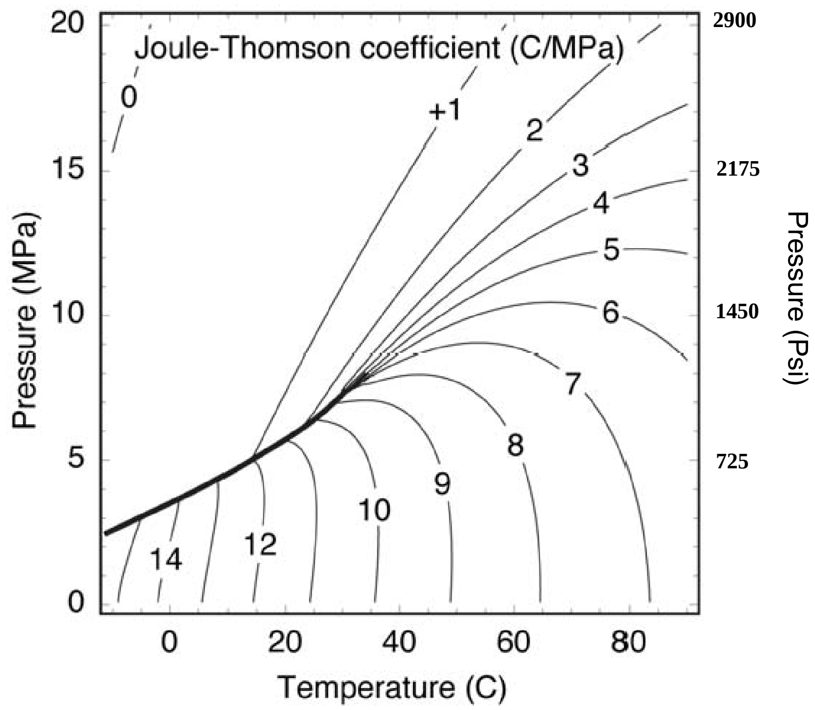


Figure 4-3: JT coefficient of CO_2 (Source SPE115946)

Well thermo-hydraulics are sensitive to the prediction of CO_2 physical properties, heat transfer between the fluid and the well bore and the frictional pressure drops.

4.1.1 Close in Conditions

Different CO_2 phases exist in a static well at geothermal conditions (83 °C bottom hole and 7°C in surface) depending on reservoir pressure assuming a well full with CO_2.

For low reservoir pressures (≤3500psia, [≤241.3bara]), the top of a well will be at saturation conditions (liquid gas consisting of mainly gas) whilst in dense phase at the bottom of the well.

With different reservoir pressures, the transition depth between gas and dense phase inside tubing will vary. Increasing reservoir pressure will move the transition point shallower. For Goldeneye reservoir pressures lower than ~3,000psia [206.9bara], the CITHP remains about the same at ~37bara [537psia] (depending on surface temperature). For reservoir pressures above 3,000psia [206.9bara], the CITHP increases with reservoir pressure. Figure 4-4 shows the pressure profile below for closed-in conditions of a Goldeneye well filled with CO_2:

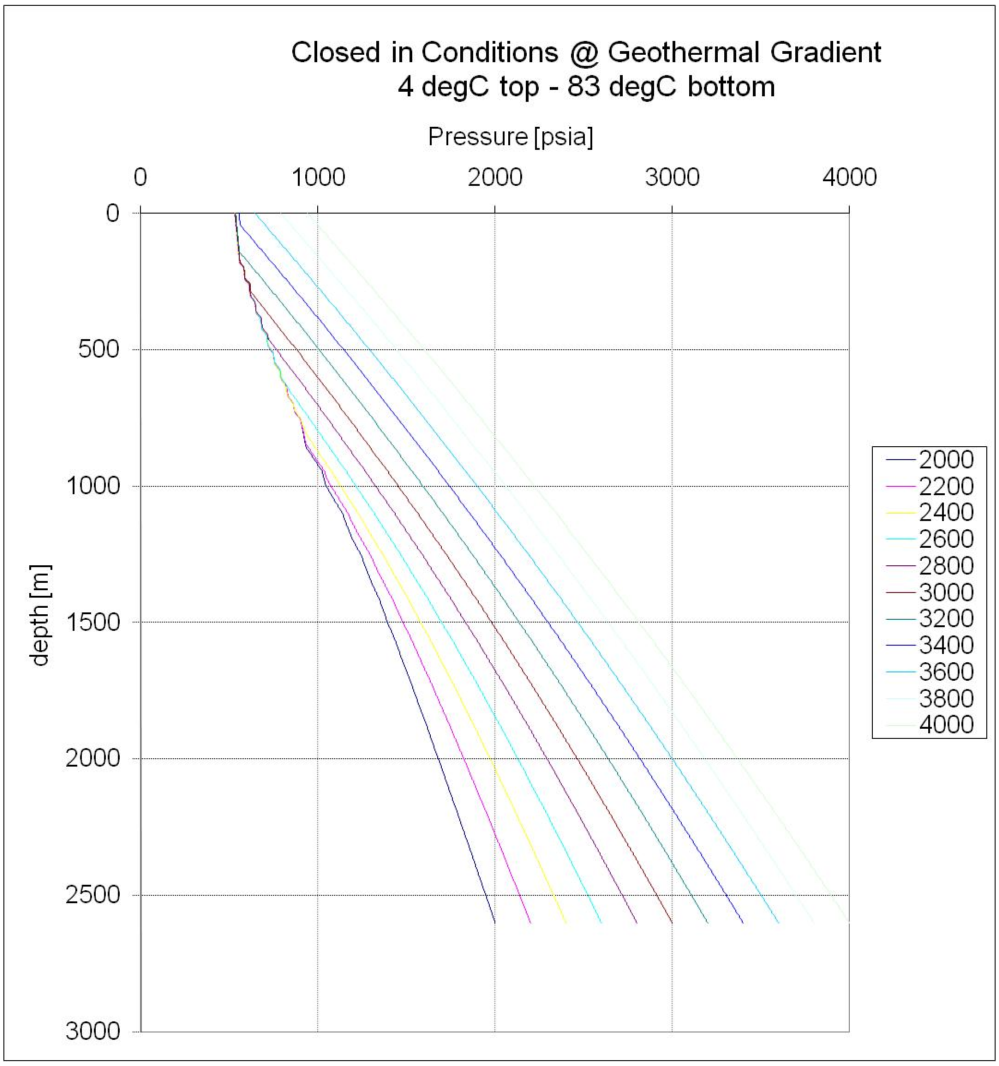


Figure 4-4: Pressure profile in a closed-in well (at geothermal conditions).

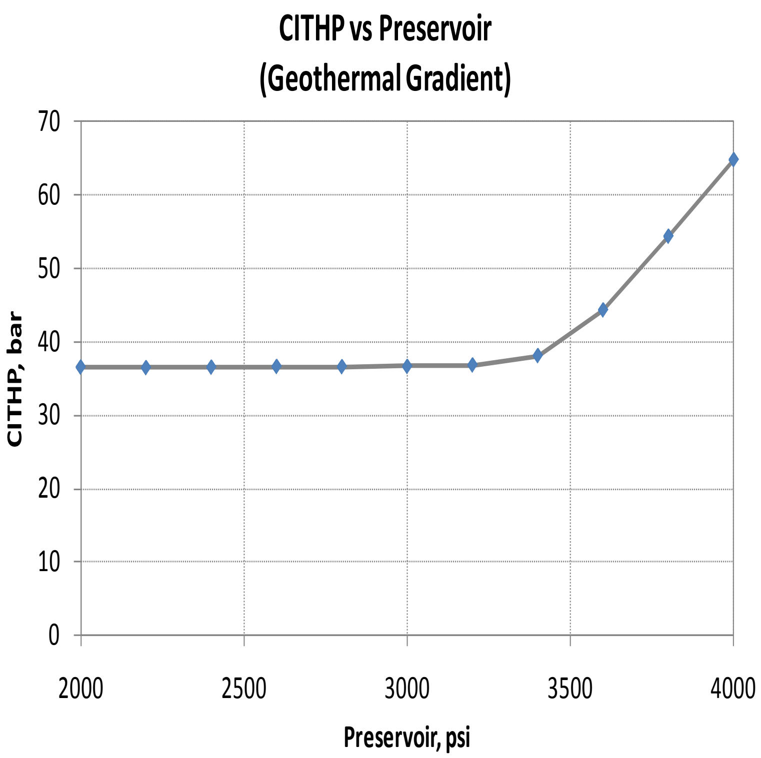


Figure 4-5: CITHP for a well filled with CO_2 (at geothermal conditions)

4.1.2 CO_2 Expansion

CO_2 will arrive at the Goldeneye infrastructure in liquid state between 2.3 and 10.1 °C depending on the season of the year and 120bara approximately (section 4.3.2).

During injection and in the case that the top of the well is operated in two phases (liquid-vapour CO_2) in an free expansion then the resulting temperature in the top of the well can be extremely low (with a minimum of -25°C and sub-zero centigrade above ~2600ft [792.5m] TVD) during the injection time. With increase of the reservoir pressure the degree of cooling is less severe. The top part of the well is operated in two phases (liquid-vapour) and the bottom part of the well is operated in single phase (Figure 4-6).

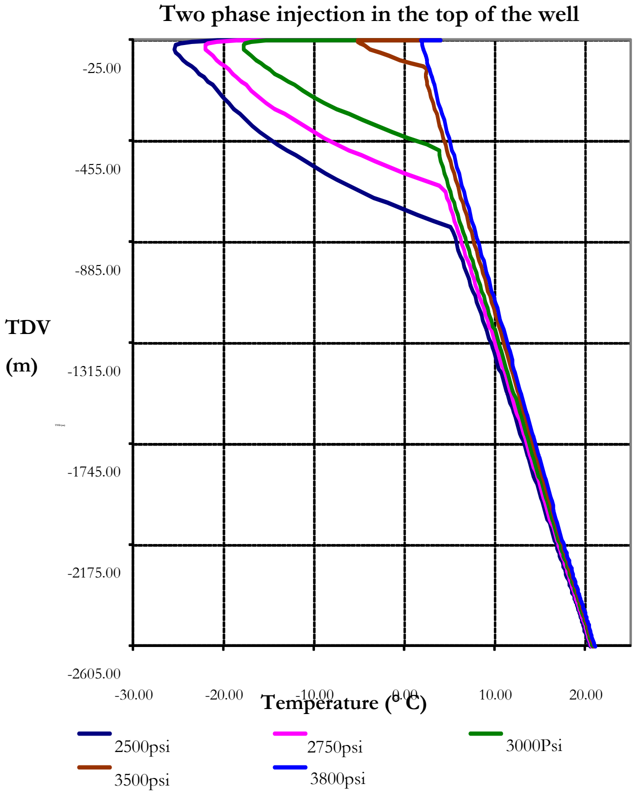


Figure 4-6: Temperature profile in the well considering CO_2 injection in two phases in the top of the well by expanding the liquid CO_2 from the pipeline

The extreme reduction in temperature is due to the flashing of the liquid CO_2 to gas/liquid CO_2 caused by the low reservoir pressure. Even at relatively high reservoir pressures there will be a flashing into two phases, mainly related to the high density of the CO_2 in the bottom of the well.

A well might be operated with free CO_2 expansion once the reservoir pressure increases to levels close to hydrostatic as the density of the CO_2 will be similar to the density of liquid water.

The general isenthalpic expansion from liquid CO_2 (arrival CO_2 conditions to Goldeneye platform) is represented in the Figure 4-7. If the CO_2 is kept in liquid phase then there will be a small reduction in temperature for big pressure drops. If the liquid CO_2 is expanded down to the saturation line, then there will be an important reduction of temperature for a small change in pressure; the CO_2 will follow the saturation line.

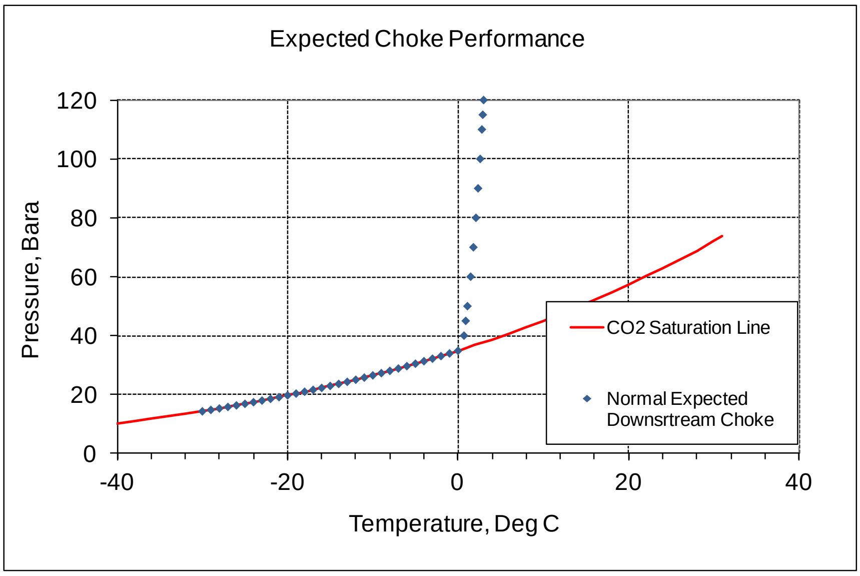


Figure 4-7: General expected CO_2 surface choke performance

The existing wells cannot be operated under these conditions of free CO_2 expansion (section 5.2 in this report). It is necessary to operate the wells controlling the CO_2 expansion during injection.

4.2 Steady State Injection Philosophy

A way of managing the potentially extremely low temperatures in the well during injection is by keeping the CO_2 stream in liquid phase at the wellhead, by increasing the required injection wellhead pressure above the saturation line. This can be achieved by extra pressure drop in the well by use of small diameter tubing creating back pressure by friction pressure loss or an important pressure drop device (downhole choke).

The concept of managing the phase behaviour of the CO_2 was presented by (Haigh, 2009). He proposed the management of the wellhead pressure in the wells (by a downhole choke or friction) in order to manage the phase behaviour of the CO_2. Use of insert strings was proposed as a way for the transition between gas phase injection to liquid phase injection.

The Figure 4-7 above shows the predicted Pressure and Temperature of flashing the CO_2 in liquid phase. If the CO_2 remains in the liquid phase the change in temperature is small for changes in pressure. However if the CO_2 reaches the saturation line (liquid-vapour), for a very small change in pressure, a very large variation in temperature is observed (follows the saturation line). The minimum wellhead pressure to avoid the CO_2 in two phases has been determined at 50bara considering the maximum arrival temperature of the CO_2 to the platform (section 4.3.3).

Increasing the pressure in the well can force the CO_2 to stay away from the saturation conditions. The WH pressure can be operated above the saturation line. The resultant wellhead temperature will be in the design range (above 0°C under steady state conditions).

With appropriate size in upper completion the WH pressure may be increased to the extent that it lies above the saturation line. As such, the minimum WH Pressure in the well is determined by the requirement of operating the well in single phase.

Transient effects will occur when the well is closed in and opened up resulting in low temperatures as the CO_2 cannot be maintained in single phase in the top of the well (section 4.4).

4.3 Steady State Pressure and Temperature Calculation

4.3.1 Software

Prosper (a commercial software marketed by Petroleum Experts, UK) is used for all calculations on Steady State. The Shell proprietary software WePs© (Well Performance Simulator) (Copyright of this program is vested in Shell International Exploration and Production BV, Rijswijk The Netherlands) has also been used to confirm the Prosper calculations. The differences are negligible.

All the five wells (GYA01, GYA02S1, GYA03, GYA04 & GYA05) with proposed completion options are modelled using Prosper/WePs.

The temperature change of the CO_2 over a tubing section is governed by the energy balance which dictates the change of the total energy. The change in temperature is caused by heat transfer, change of potential energy, change of kinetic energy (acceleration) and change of enthalpy due to expansion. The effect of adiabatic cooling, and Joule-Thompson cooling and phase changes are taken into account. These calculations are implemented in Weps and Prosper considering the well construction, the overburden description and the fluid description.

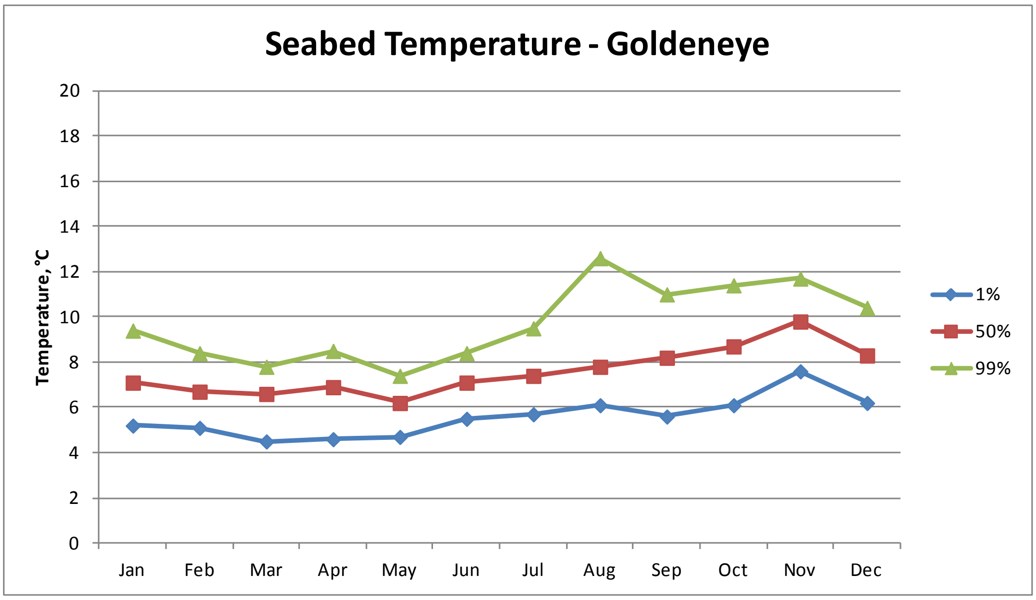
For each section, the pressure drop across the section is calculated using a multi-phase pressure drop correlation. Based on the section properties, such as diameter and inclination angle, a multi-phase pressure drop correlation is used to calculate the flow regime, gas and liquid hold ups, and subsequently the pressure drop.

The vertical lift performance under steady state conditions is relatively simple to calculate considering that there is only 1 phase of dense phase CO_2. Prospers use the Peng Robinson equation of state to model the CO_2 properties. It is calibrated for the Goldeneye conditions (Appendix A in the report (UKCCS-KT-S7.18-Shell-001 Temperature and Pressure Modelling (for CO2 injection wells - Goldeneye CCS), 2010).

4.3.2 Arrival temperature to the platform and wellhead temperature

Wellhead temperature will range from 0.5°C to 10°C. The CO_2 stream arrival temperature to the platform would be between 2.3°C to 10.1°C depending mainly on seabed temperature. The wellhead temperature would also depend on the expansion degree of the CO_2 in the surface facilities.

The minimum and maximum arrival temperatures in the platform in winter and summer times considering the extreme temperatures which can be used for design purposes have been considered. The variation in the P50 seabed temperature is between 6°C and 10 °C. The P50 sea surface temperature has a variation between 7°C and 15 °C.



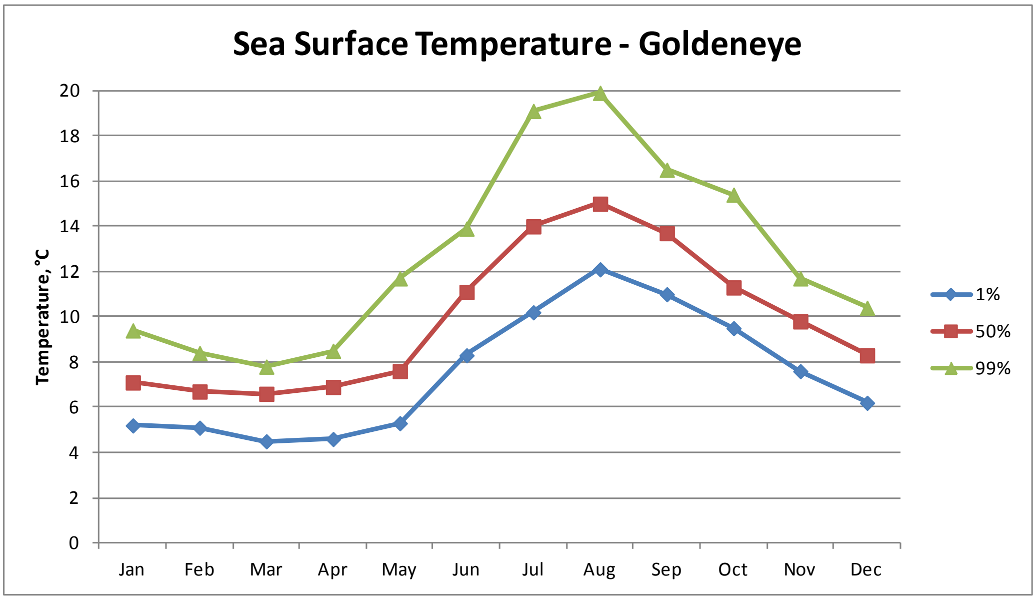


Figure 4-8: Sea temperature at the Goldeneye area

The minimum arrival CO_2 temperature to the platform in winter of 2.3°C should be used for low temperature calculations. The high temperature of 10.1°C should be used for limits of the injection system. The temperature drop between the seabed and the CO_2 arrival temperature is estimated at 1.7 °C for winter conditions and approximately 1 °C in summer.

The expected manifold conditions in winter would be 5.3°C considering an average seabed temperature of 7°C and a temperature drop of 1.7°C at the riser. For an isenthalpic pressure drop in the surface facilities to 115bara wellhead pressure, the wellhead temperature would be in the order of 5.2°C (3.1°C for 50bara wellhead pressure). These temperatures would be used for normal well operational calculations. In summer the expected wellhead temperature is 5.5°C for 50bara tubing head pressure and 7.9°C for 115bara.

Table 4-1 summarises the expected temperatures for the operational and design cases to be used in this report.

Table 4-1: Arrival CO_2 temperature to the platform for different cases and subsequent expansion to wellhead conditions

	Design Minimum (Winter)	Operational (Winter)	Operational (Summer)	Design Maximum (Summer)
Goldeneye Site Air temperature, °C	-8.2	7	12	24.5
Goldeneye Site Sea surface temperature, °C	1.0	7	14	21.0
Goldeneye Sea bed temperature, °C	4.0	7	9	11.0
Arrival CO_2 temperature to the platform °C (120bara)	**2.3**	5.3	8	**10.1**
Isenthalpic expansion to 115bara, °C	2.2	5.2	7.9	**10**
Isenthalpic expansion to 50bara, °C	**0.5**	3.1	5.5	7.2

A temperature of 5°C will be used for reference case simulations as the injected CO_2 temperature. This is the average for the summer and winter design cases and also the average temperature of the operational cases. Sensitivities will be carried out for the different cases in injected CO_2 temperatures when required.

4.3.3 Wellhead pressure range

The current philosophy is to inject CO_2 in single phase liquid in the top of the well keeping wellhead pressures above the saturation line to avoid extremely low temperatures in the well caused by the Joule Thomson effect.

There should be enough difference in pressure between the minimum wellhead pressure and the CO_2 saturation pressure to avoid potential damage to surface equipment (e.g. cavitation problems). A minimum margin of 50psia [3.5bara] between the minimum wellhead injection pressure and the saturation pressure is suggested.

The maximum expected manifold temperature is 10.1 °C. The saturation pressure for temperature is 45.13bara. The minimum WH pressure for operating the wells would be 48.63bara (45.13+3.5). A 50bara minimum pressure has been selected as the minimum WH pressure to operate the wells, Figure 4-9.

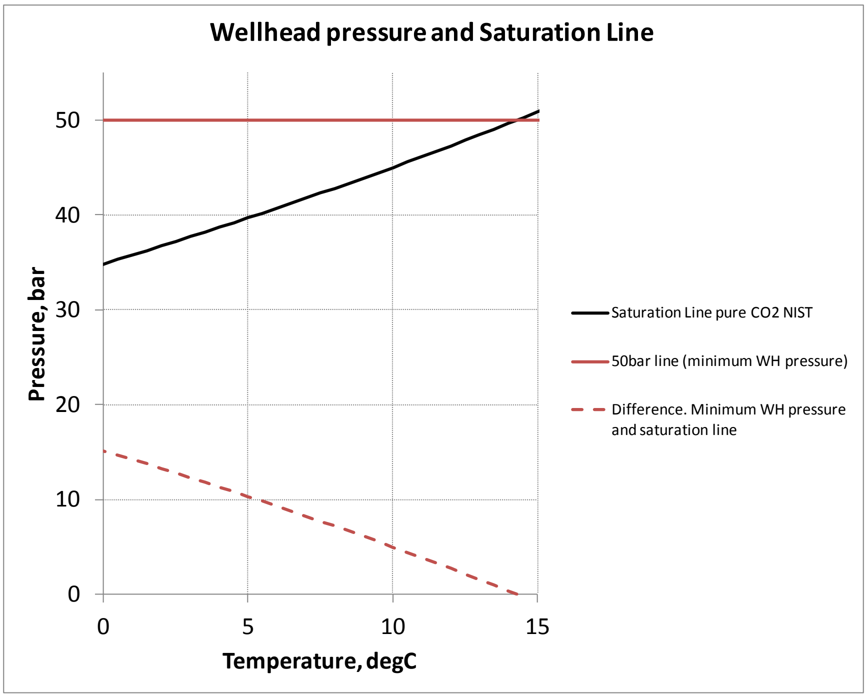


Figure 4-9: Wellhead pressure and pure CO_2 saturation line. Difference in pressure between minimum injection pressure and saturation curve.

It is important to mention that the expected injection range per well can be expanded by reducing the minimum WH pressure but maintaining it above the saturation pressure. 50bara has been used at the moment in the project as a conservative pressure considering the maximum manifold temperature in summer. The WH temperature can be reduced with colder arrival temperature of the CO_2. For example, a way of operating the wells would be to reduce the minimum WH pressure in winter to a lower value (43.5bara considering a CO_2 manifold temperature 5.3°C and saturation pressure of 40bara).

The maximum WH pressure is limited by the maximum allowable pipeline pressure. A CO_2 arrival pressure to the platform of 120bara has been highlighted. Considering pressure drops in the surface equipment (filters, meters, valves, etc.) a maximum available pressure of 115bara at the wellhead has been used in the calculations.

4.3.4 Other input

Reservoir temperature of 83°C is given as an input at a depth, mid of Captain D. Water depth for Goldeneye wells is 396ft [120.7m] from MSL. Reference depth datum is 152.5ft [46.5m].

For modelling purposes, sea surface temperature is 10°C and seabed temperature is 7°C. Air temperature is simulated with 7 °C (simulations were carried out to evaluate the effect in the CO_2 pressure and temperature for different sea and air temperatures, the effect is negligible; the arrival temperature of the CO_2 is the important factor).

Using the seabed temperatures and reservoir temperatures, overall geothermal gradient is defined by the software.

Overburden/lithology data is also used as an input for temperature profile analysis across the tubing. Each lithology section includes formation thickness, density, specific heat & conductivity.

Water/Brine Packer fluid (or A-annulus fluid) is assumed in this report. New calculations of lift performance will be done for the selected packer fluid.

4.3.5 Steady state operating envelope – reference case

The operating range of a well is defined with the injectivity curve or inflow performance at a given reservoir pressure and the vertical lift performance. Under steady state injection, the well should not inject below 50bara due to the JT characteristics of the CO_2; this will generate a minimum rate that the wells can manage. The maximum injection rate per well is given at the maximum injection pressure of ~115bara. The concept is presented below, **Figure 4-10**.

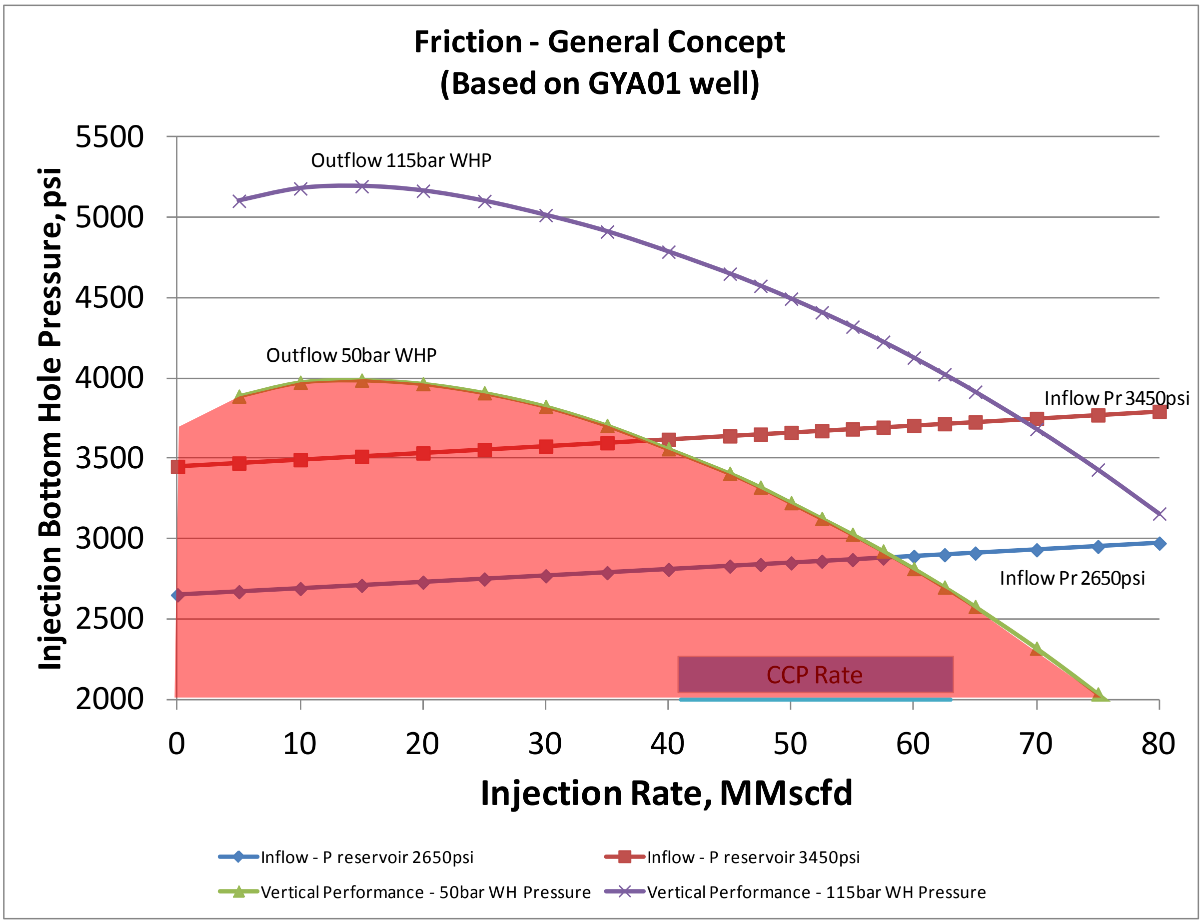


Figure 4-10: Friction Dominated Concept. Inflow and Outflow.

4.3.6 Steady state - Different tubing sizes

The operating envelope of the well can be designed by installing different tubing sizes. In the friction concept a larger tubing diameter will provide a big well on injection rate and a smaller size will provide a smaller well. The inflow plays a minor role (when remains stable and there is not significant deterioration of injectivity) in comparison to the choice of tubing size, Figure 4-11.

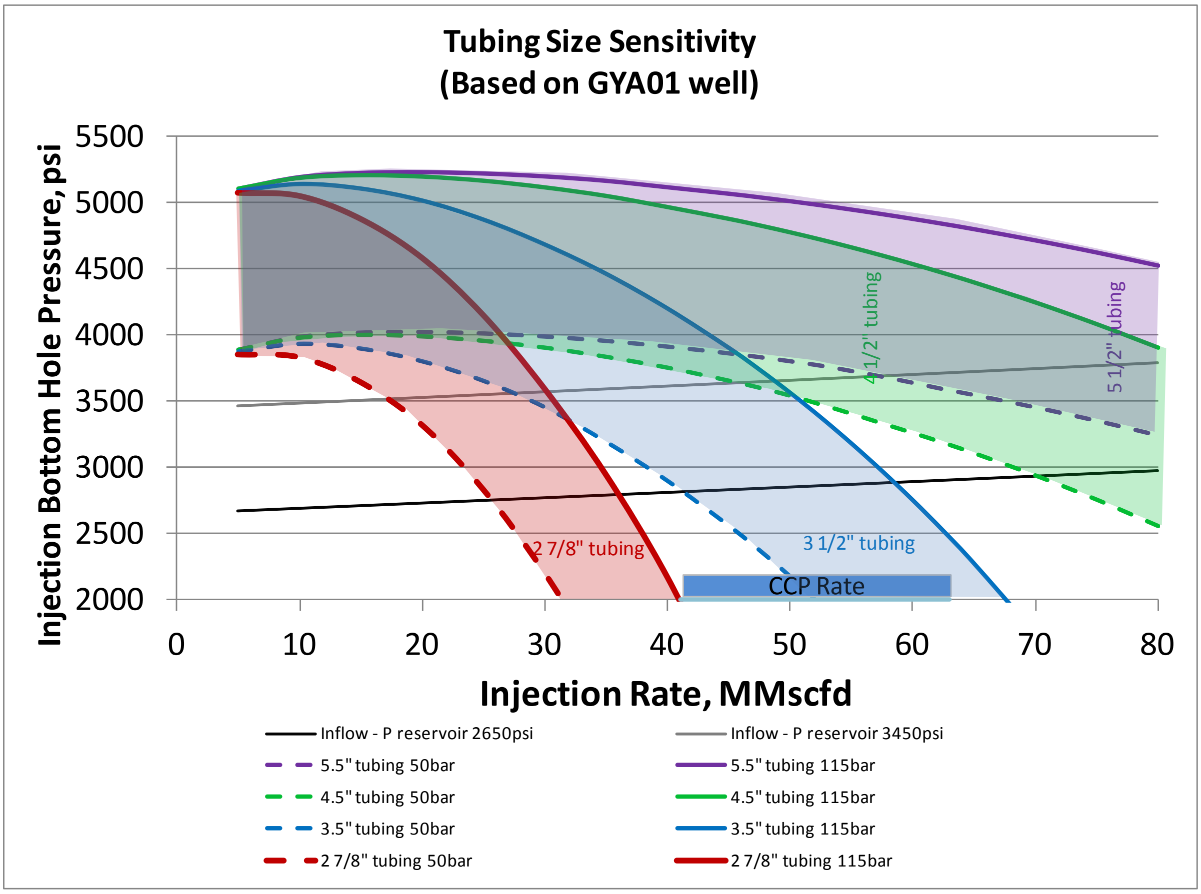


Figure 4-11: Friction dominated concept. Sensitivity to tubing sizes

The 2 7/8" [73mm] tubing is considered very small and the 5 ½" [140mm] tubing seems very big for the Peterhead CCP rates. The tubing size required for the CCP rates is a combination of 3 ½" [89mm] and 4 ½" [114mm] completion.

The operating envelope per well will be engineered/tailored well by well considering the lifecycle of the project parameters (expected reservoir pressure, CCP rates, etc.).

4.3.7 Steady State - Wellhead Temperature Sensitivity

The injection temperature is an important factor in determining the operating envelope per well. If the wellhead temperature increases the capacity of injecting CO_2 in the wells decreases (at the same pressure conditions) due to the CO_2 density variations.

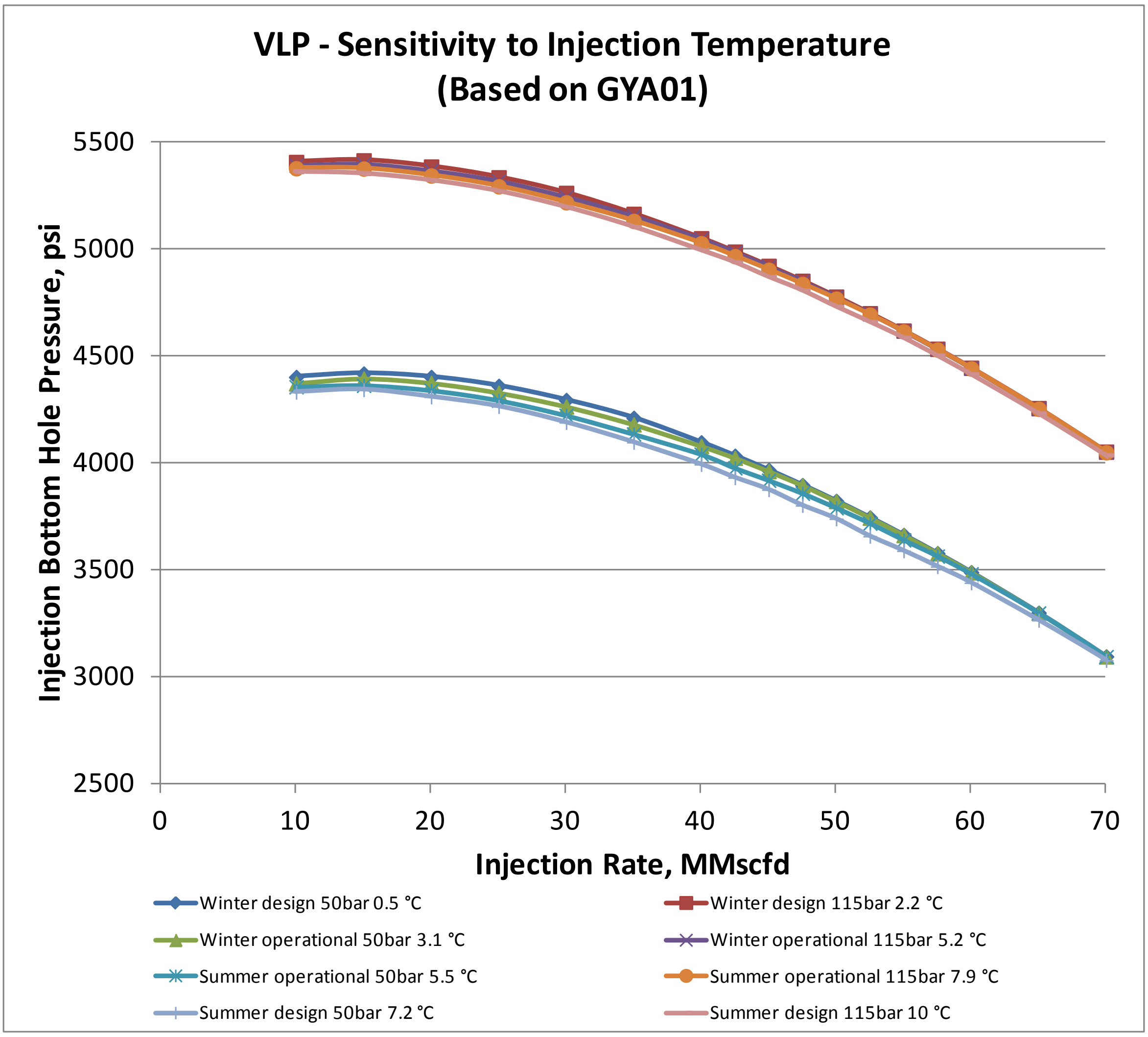


Figure 4-12. Friction dominated concept. Sensitivity to wellhead temperatures

There is some variation in injection rate per well due to the CO_2 temperature (when considering the extremes for winter and summer) which needs to be considered for meeting the minimum and maximum rates of the CCP.

4.3.8 Steady State – Roughness Sensitivity

Roughness of the used tubing material is critical for the frictional pressure drop. The Roughness of Bare 13Cr is used as the reference case,

Table 4-2 . For the low roughness case, the electropolished bare – 13 Cr tubing roughness is used. Electropolished 13Cr has had the scale formed during manufacturing removed. (Bellarby, 2009) . A high roughness value of 25% above the reference case is used. Rusted Carbon Steel is not used in the calculations as no carbon steel will be used in the tubing.

Table 4-2: Steel Roughness.

	Average absolute	Remarks

	Roughness, in / micron	
Bare 13Cr	0.0021654 / 55	Used as reference case
Electropolished bare - 13 Cr	0.00118 / 30	Low Value
Bare Carbon Steel	0.00138 / 35	Not to be used in the wells
Clean Carbon Steel	0.000787 / 20	Not to be used in the wells
Rusted steel	0.00394-0.0394 / 100-1000	Not to be used in the wells
+ 25 % above Bare 13Cr roughness	0.0027 / 69	High Value

Sensitivity was carried out for different average absolute roughness values, Figure 4-13. There are some variation terms of injection rate per well. Variations in the order of ~+/- 3 MMscfd in injection rate for the low and high roughness case with respect to the reference case are calculated.

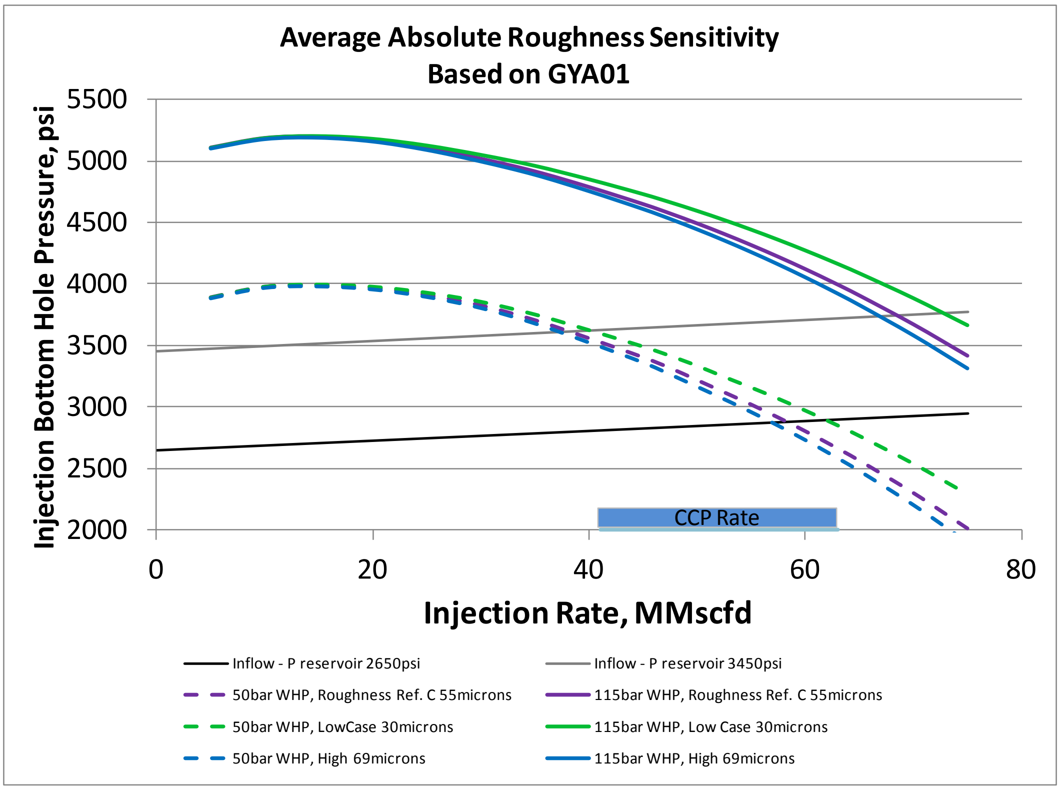
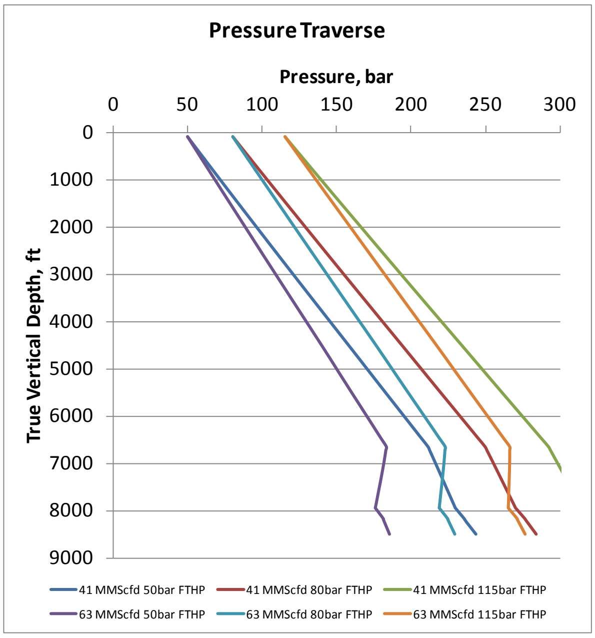


Figure 4-13: Friction dominated concept. Sensitivity to steel roughness

Roughness of the tubular to be purchased will need to be investigated in order to estimate the final tubing design.

4.3.9 Steady State - Traverse Pressure and Temperature Calculations

Pressure and Temperature traverses in the well (based on GYA01) are presented in the figure below. Total frictional losses of around 40 to 100bara will be encountered in the wells depending on flow rate.



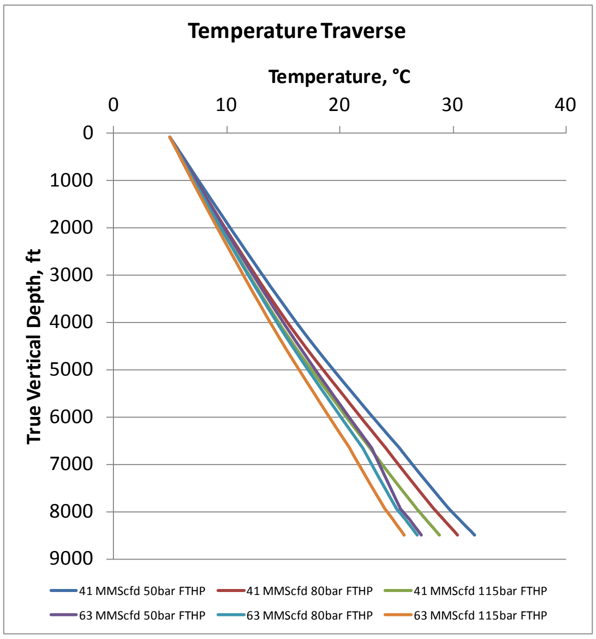


Figure 4-14: Pressure and Temperature predictions under steady state

The CO_2 will be injected in the tubing of the well at single phase (dense phase). The PVT properties of the CO_2 are well defined in this region as observed in the Figure 4-15 where the CO_2 density is relatively stable travelling down the well. This will minimise the calculation error in terms of the operating envelope of the wells and pressure traverses.

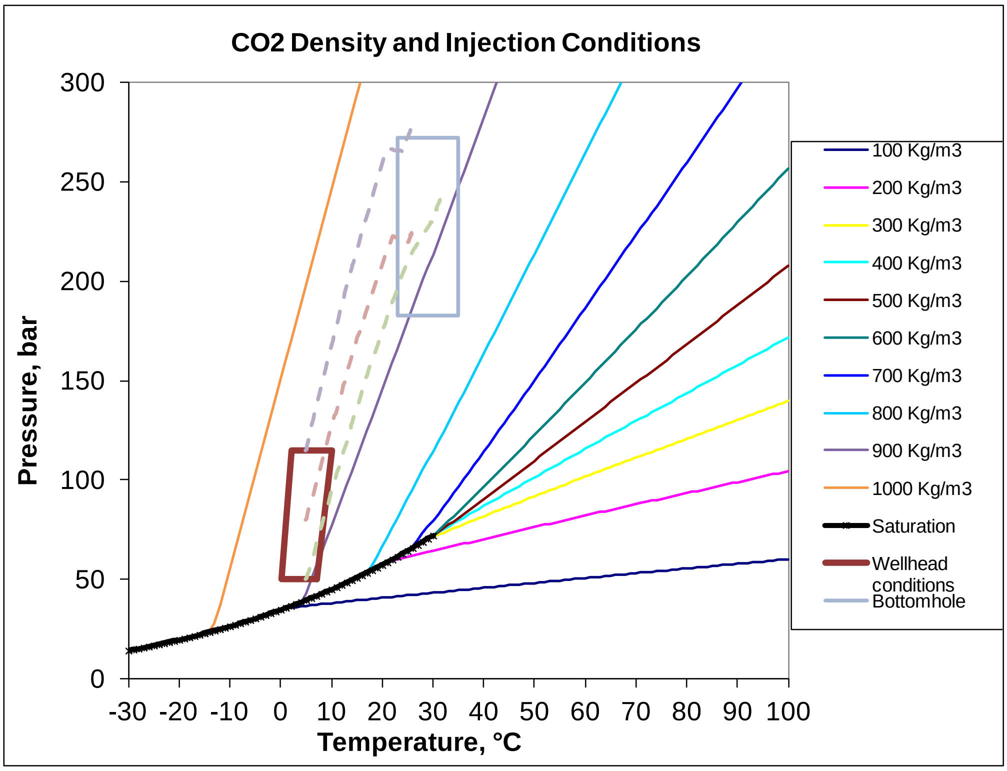


Figure 4-15: Pressure and Temperature prediction with respect to CO_2 phase envelope and density

4.3.10 Steady State – Bottom Hole Temperature ranges

The bottomhole temperature (BHT) will depend on the injected fluid temperature and the rate of injection. For the CCP rates in the Peterhead project, the expected BHT is between 23°C to 35°C, Figure 4-16.

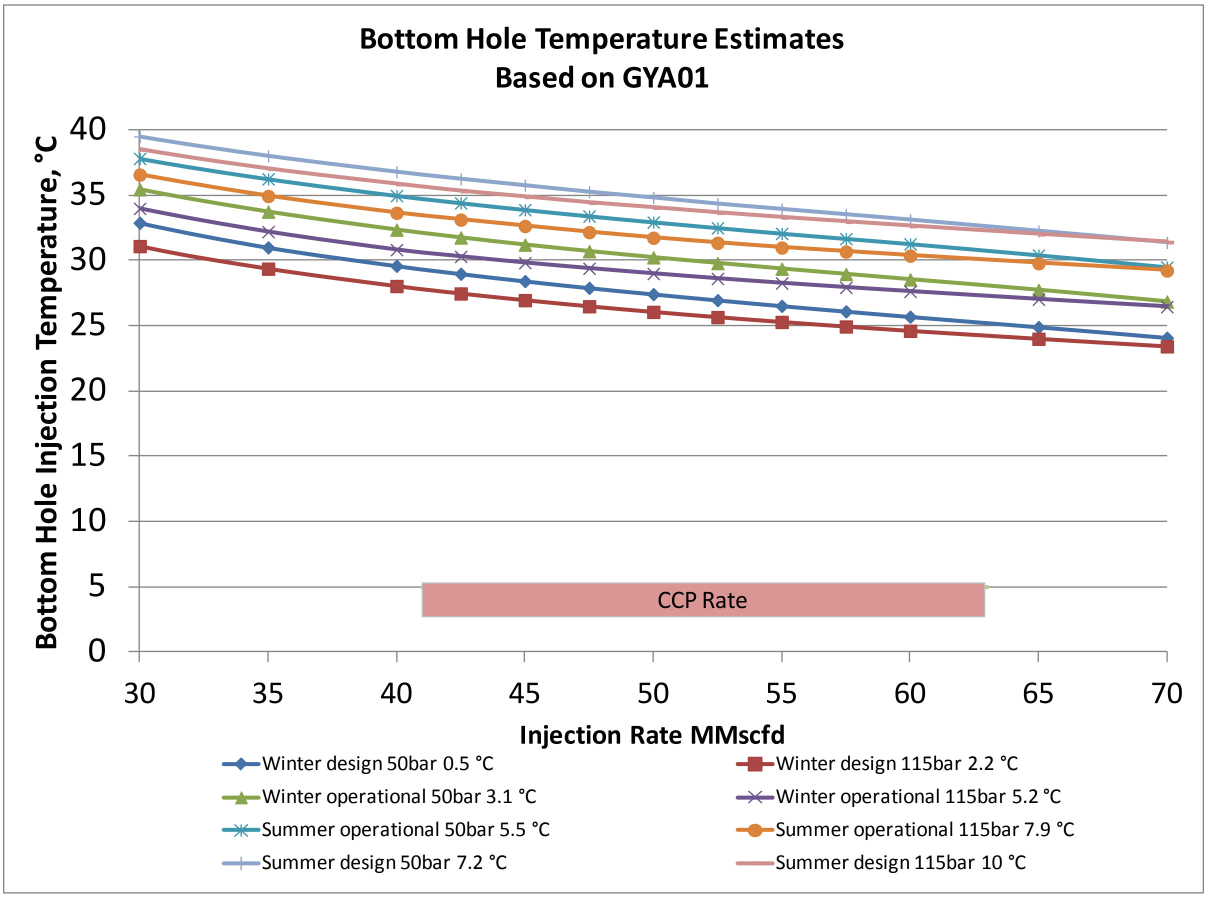


Figure 4-16: Bottomhole injection temperature sensitivity

4.3.11 CO_2 velocity and vibration

The concept for the well design is to use a friction dominated scenario by high velocities. This concept is used to restrict production from wells. The concept has been discussed in the industry (Haigh, 2009) to overcome the CO_2 Joule Thomson effect in depleted reservoirs but has not been implemented to date.

Friction is a well-known effect in fluid thermodynamics. The extension of management CO_2 phase behaviour by the use of friction is a logical step.

The bottomhole pressure depends mainly on CO_2 density and tubing friction (back pressure). Different values for steel roughness have been used to derive the frictional losses in the well,

Table 4-2. The wells will be controlled by wellhead pressure. That is if there is not enough friction then the injection rate should be increased to the minimum pressure value of 50bara - to keep the CO_2 in the dense phase. The other mitigation factor is the overlapping of the different well envelopes.

The CO_2 in the well will have a high density 900-970kg/m^3 depending on pressure and temperature and it is liquid in the top of the well. The maximum velocity suggested for liquid guidelines APIRP14E or ISO13703 is 4.6 or 5.0m/s respectively for continuous service. These guidelines are mainly used in the design and installation of offshore production platform piping systems. Sudden change in flow directions is included in the guidelines. However, the trajectory of Goldeneye wells is smooth enough not to cause changes to flow directions. Well experience across the world has shown that the guidelines are conservative and higher values in velocity are normally used in the industry.

Operators have reported using 10m/s in water injectors wells completed with carbon steel; the velocity is increased to 17m/s for a duplex stainless steel or higher grade alloy.

Similarly 50m/s for gas hydrocarbon production has been used on a continuous basis. This is equivalent to around 16m/s for CO_2 injection using the C-factor for the ISO 13703 or APIRP14E (Figure 4-17).

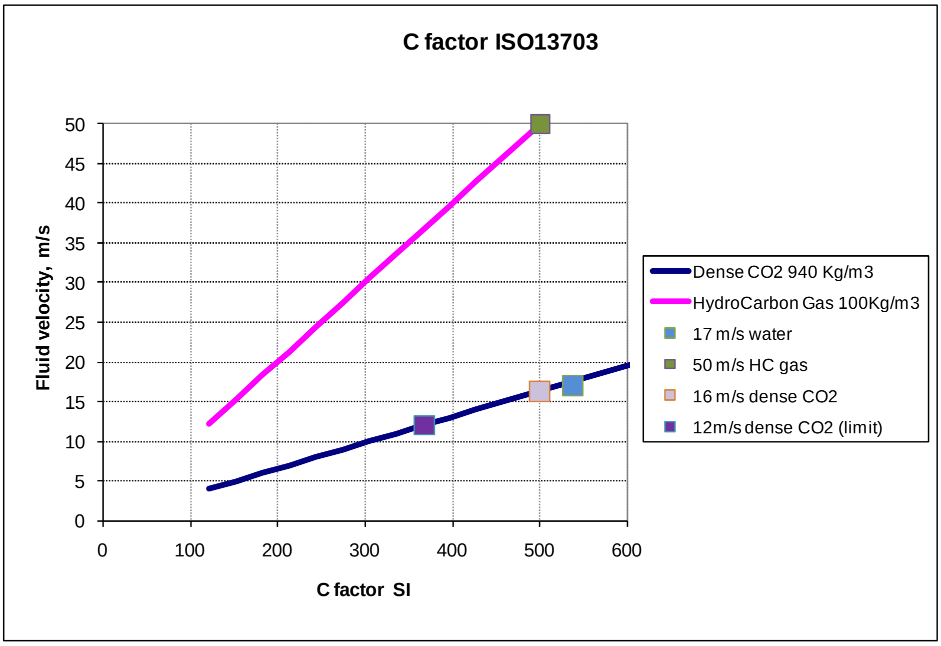


Figure 4-17: C factor comparison (from ISO13703) for CO_2 and hydrocarbon gas

Furthermore the erosion of the metal is not considered to be an issue. Erosion is not generally a result of surface shear, but is usually a result of repeated, micro- (1) metal deformation or (2) fracture damage as a result of a mass (solid in liquid or gas, liquid in gas) changing direction at a metal surface. No "mass" changing direction equals no erosion.

Due to the high flow velocities and turbulent fluctuations in the fluid, pulsations and vibrations in the tubing can be expected. Both the vibration of flow turbulence and the intrinsic instability of the tubing due to large fluid momentum in the tubing were examined by TNO (TNO-RPT-DTS-2011-00573, 2010). The tension in the tubing created during the installation and subsequent injection of cold CO_2 removed the chance of fluttering or oscillation of the tubing due to large flow velocity.

Instability is caused by an interaction between the flow-induced forces and bending waves of the tubing. The part of the tubing in compression is more prone to instabilities than the part of the tubing under tension. If there is no part in compression, there cannot be any instability in a vertical pipe, for constant flow. The tubing above the packer on the full length will always be in tension. As a result the instability is considered not an issue in this part of the completion. To avoid oscillations in the tail pipe (or tubing below the production packer) a maximum length of 45.7m [150ft] is calculated.

The acoustic forces, due to turbulence and created by the crossover installed in the completion will not impact the tubing design.

In general, the TNO study recommended: to keep the tail pipe as short as possible, make sure the tubing remains under tension during operation and use large diameter tubing near the packer.

A maximum velocity in the tubing of 12m/s will be used in restricting the wells envelope. This value includes a safety factor of 0.75 over the equivalent (C factor) experienced gas producing maximum velocity in wells. This value is also in line with water injection values reported in the industry.

The 12m/s maximum velocity is equivalent in having the following injection rates in different tubing sizes, Table 4-3. If the 3 ½" [89mm] tubing is going to be used then the maximum injection rate per well would be 68 MMscfd which is higher than the capacity of the capture plant (63 MMscfd).

Table 4-3: Maximum injection due to velocity in tubing [1" = 25.4mm]

Tubing Size, in	Internal Diameter, in	In-situ Injection Rate for 12m/s in the tubing, m^3/d	Injection Rate for 12m/s in the tubing, MMscfd (CO_2 ~ 970m m^3/d)
4 ½"	3.958	8230	120
3 ½"	2.922	4700	68
2 7/8"	2.441	3130	45

4.3.12 Steady State – Downhole choke option

Downhole chokes were investigated for the Longannet-Goldeneye CCS study in order to manage the CO_2 phase. It was considered unreliable due to the high differential pressure requirement (~1200psia [~83bara]), the small orifice requirement (6-9/64" [2.38-3.57mm]) and the variability in differential pressures and rates across the choke for small changes in diameter (choke erosion can lead to dramatic changes in differential pressure).

New calculations have not been carried out for this type of completion. The following is extracted from the Longannet report (UKCCS-KT-S7.18-Shell-001 Temperature and Pressure Modelling (for CO2 injection wells - Goldeneye CCS), 2010) on downhole chokes.

The same principles apply in terms of minimum WH pressure of 50bara and maximum 115bara at the WH defining the operating envelope of the wells.

The current completion (7" [178mm] tubing) has been used to model this case. A downhole choke set at 1700m AHD (5578ft AHD). The depth was chosen considering that at closed in conditions there would not be any CO_2 in vapour phase at this given depth.

The required size of the downhole chokes was first investigated for the CO_2 in single phase along the well as shown in the Figure 4-18 for an injection pressure of 2500psia [172bara]. The range of choke sizes would be in the order of 6/64" [2.38mm] to 11/64" [4.37mm]. The operating range for each choke size is defined between the 2 horizontal lines representing 50bara and 100bara WH pressure. For example, for a 7/64" [2.78mm] choke the minimum rate would be in the order of 27MMscfd [16.4 kg/s] and a maximum rate of 37MMscfd [22.5 kg/s] at 2000psia [138bara] bottomhole injection pressure. The operating range has an important change with the size of the downhole choke. For example the minimum rate for a 7/64" choke would be 27MMscfd whilst for an 11/64" choke the minimum rate would be 62MMscfd.

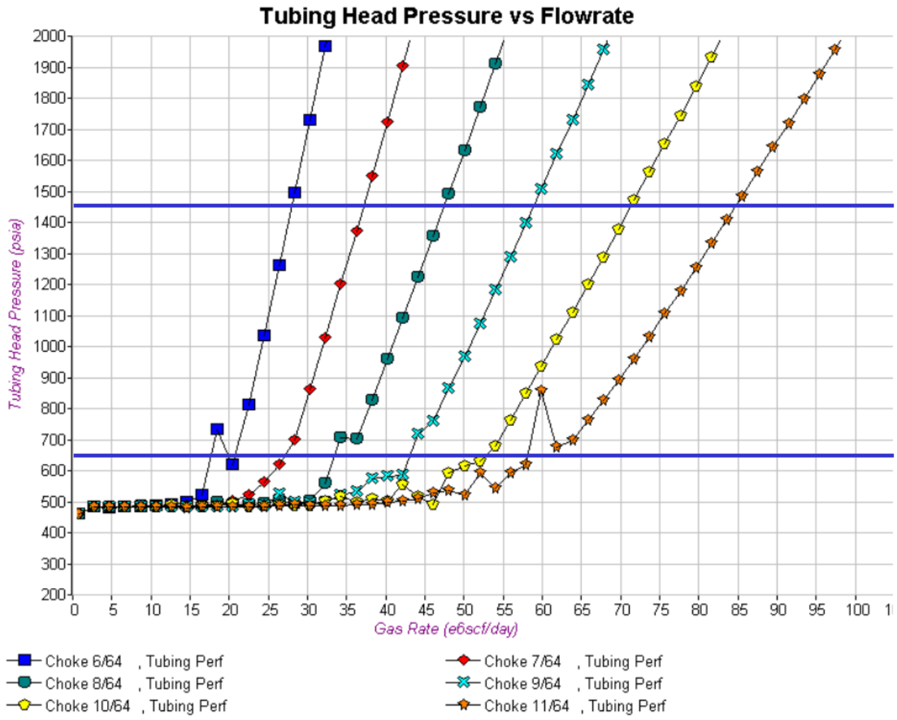


Figure 4-18: Downhole choke operating range (at 2500psia iBHP)

The pressure and temperature traverse can be represented in the Figure 4-19 for the downhole choke case for an injection pressure of 3000psia (207bara). The Pressure traverse shows the required pressure drop across the choke for the minimum (at 50bara wellhead pressure) and maximum rate (at 115bara WH pressure). The bottomhole temperature is similar to the tubing cases with bottom hole temperatures varying from 22°C to 39°C. Due to the pressure drop at the choke depth there is cooling of the CO_2 due to the Joule Thomson effect.

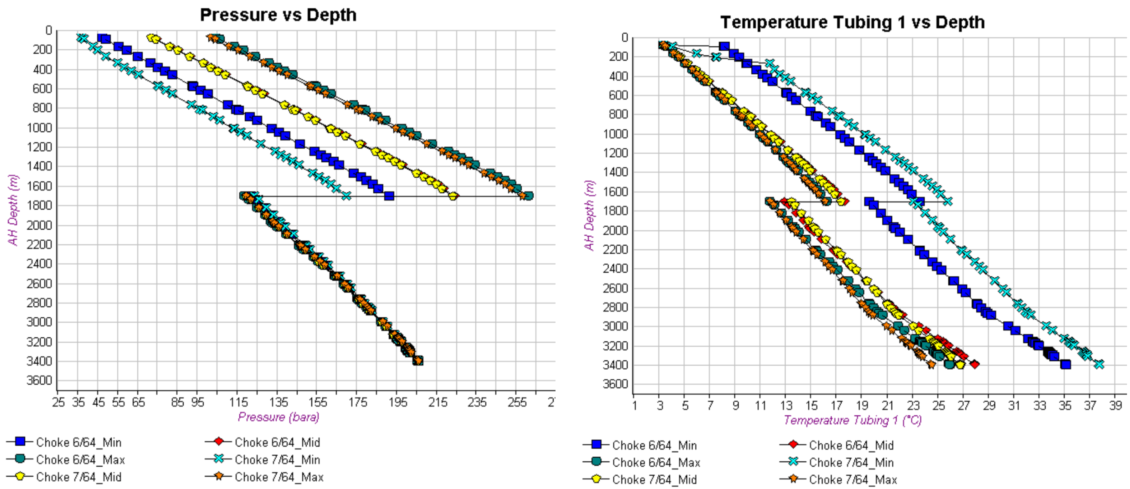


Figure 4-19: Downhole choke pressure and temperature traverse (at 3000psia iBHP)

The pressure drop across the choke is very sensitive to the choke size. The pressure drop for different choke sizes have been calculated and shown (Figure 4-20) before for an injection bottom hole pressure of 2000psia (138bara).

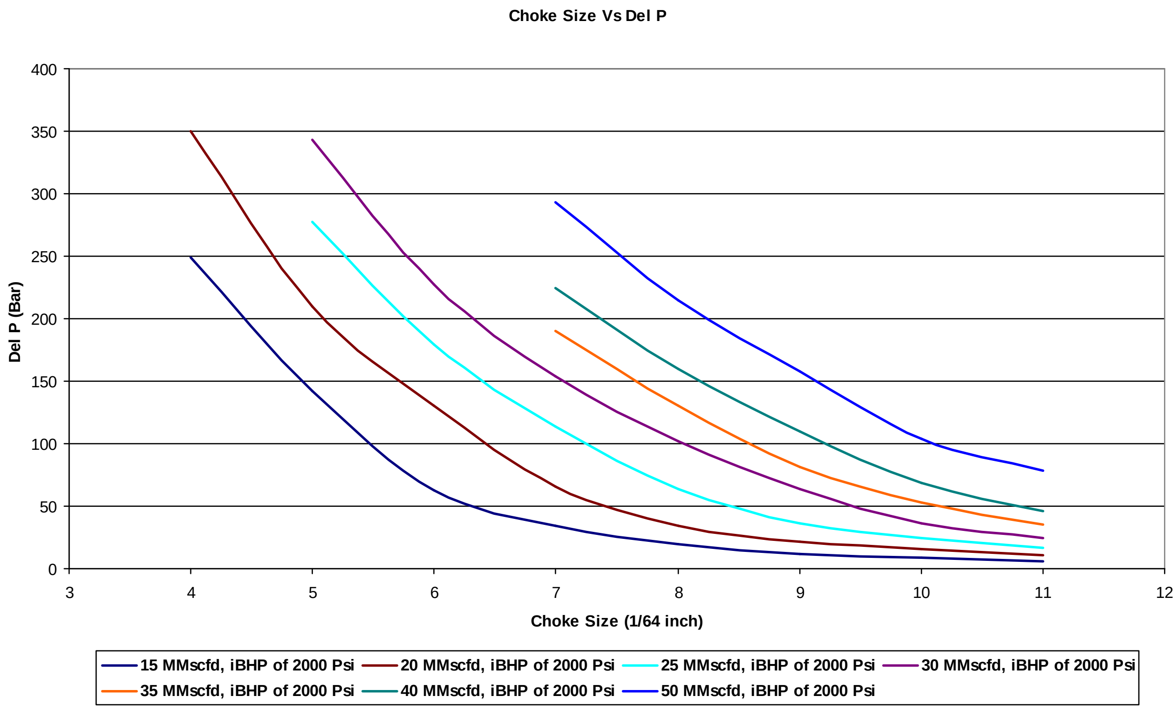


Figure 4-20: Pressure drop across a downhole choke (at 2000psia iBHP)

Some general remarks can be drawn from the downhole choke calculations:

- The downhole choke can force the CO_2 to stay in single phase at the well
- The required choke size is very small given the pressure drop required
- The operating range of a fixed size choke is very small
- Temperature drop caused by the Joule Thomson effect can be effectively managed by placing the choke at the dense phase region under closed in conditions.

4.4 Transient conditions (close-in and open-up well operations)

This section is a summary from the report (UKCCS-KT-S7.18-Shell-003 Flowline Well Interactions, 2011) where dynamic or transient calculations were performed for closing-in and opening up the wells in a friction dominated scenario. New calculations are planned during the FEED phase of the project with the Peterhead Goldeneye CCS conditions.

During transient operations (close-in and start-up operations), a temperature drop is observed at the top of the well for a short period of time. The faster the shut-in or faster the well opening operation, the less the resultant temperature drop. The cooling effect diminishes deeper into the well due to limited CO_2 flashing and heat transfer from surrounding wellbore.

The reservoir pressure affects the temperature calculation during the transient calculations. The lower the reservoir pressure, the lower is the surface temperature expected during transient operations and hence the higher the stresses/impact in terms on well design.

The recommended procedure is to bring the well to the minimum rate (rate required to keep CO_2 in liquid phase at the wellhead, i.e. injection at 50bara WH Pressure) and then close the well at the wellhead in 30 minutes. For bringing on a well on CO_2 injection, the recommended procedure is also to do it quickly. It is recommended to attain the minimum rate in 1 hour. Temperature as low as -15°C can be reached inside the tubing in the top of the well during short periods of time. Due to heat capacity/storage, this low temperature in the CO_2 is not observed in the other well components (tubing, annulus fluid, etc.), which will see less severe temperature drops. Calculated temperatures in the top of the well for the recommended case at 2500psia [172bara] reservoir pressure are shown in Figure 4-21.

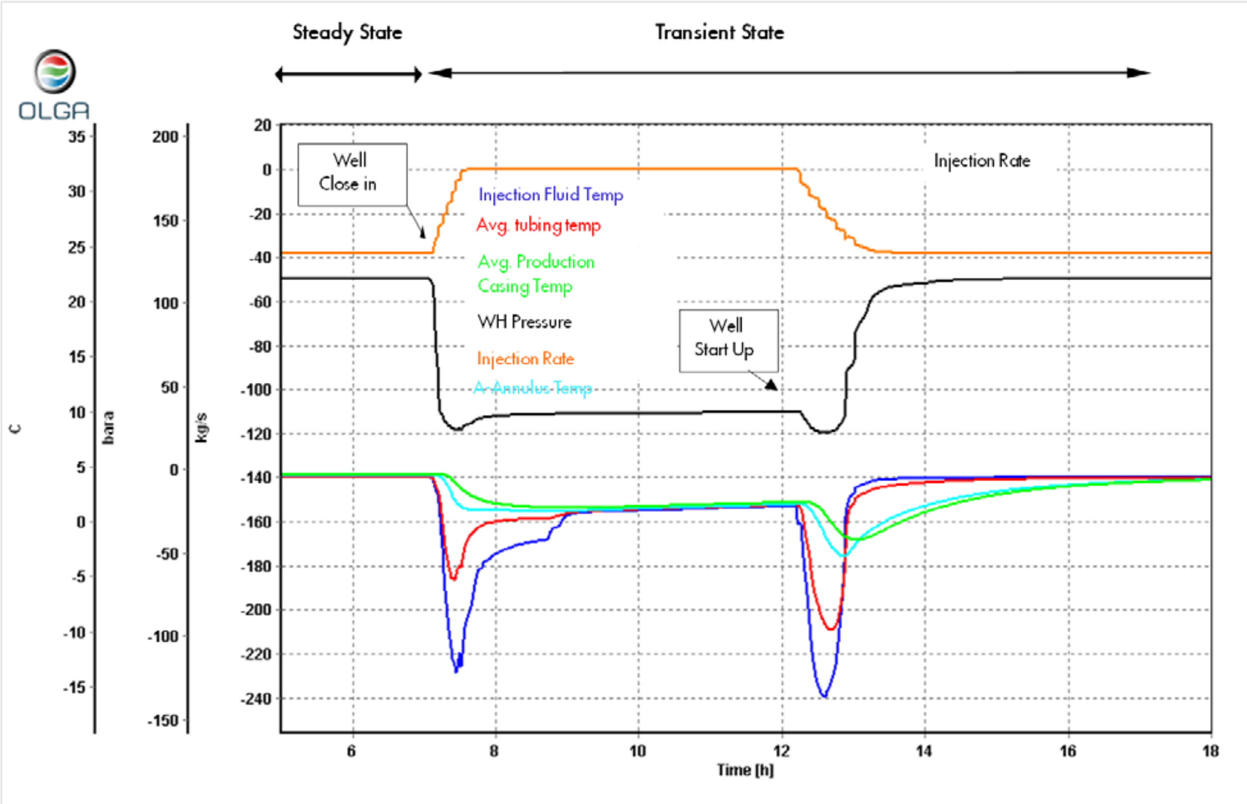


Figure 4-21: Wellhead transient temperature. Recommended operations case. Wellhead conditions. 4°C IWHT (2500psia reservoir pressure).

At ~450m depth, the CO_2 temperature in the tubing is 0°C (32°F). At reservoir depth, during CO_2 injection steady-state conditions, the temperature is constant around 17-20°C for injection surface fluid temperature of 4°C. When shut-in, this bottom hole temperature rises slowly (~2 weeks) towards initial reservoir temperature.

The design case considers a longer time to open or close the wells in case of any operational problem. Equally the reservoir pressure used in the calculations is 2500psia which is lower than the predicted reservoir pressure at the start of the CO_2 injection. For the design case, for a short period of time, surface temperature drop in the CO_2 can be in the order of -20°C during well start-up (see Figure 4-22).

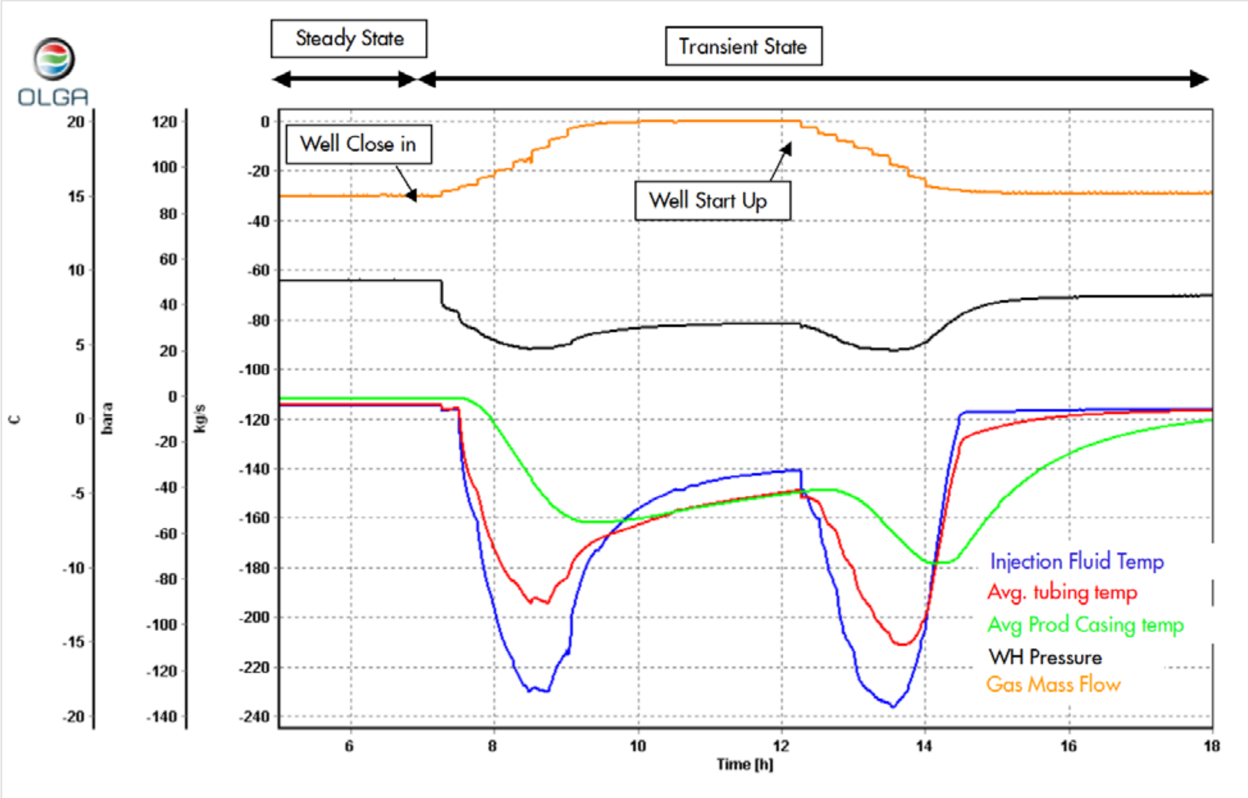


Figure 4-22: Wellhead transient temperature. Wellhead conditions. 4°C IWHT (2500psia reservoir pressure)

Figure 4-23 shows the traverse temperature profile of injection fluid, tubing and production casing at 13th hour of Figure 4-22 (the time where the coldest temperature is observed CO_2 at the wellhead). The top of the well is at low temperatures whilst the bottom of the well is close to steady state injection temperature. It should be noted that the profile plot shown below is for lowest CO_2 temperature and not for lowest tubing or production casing temperature. There is a time lag observed for the lowest temperature in tubing and production casing with respect to injection fluid temperature.

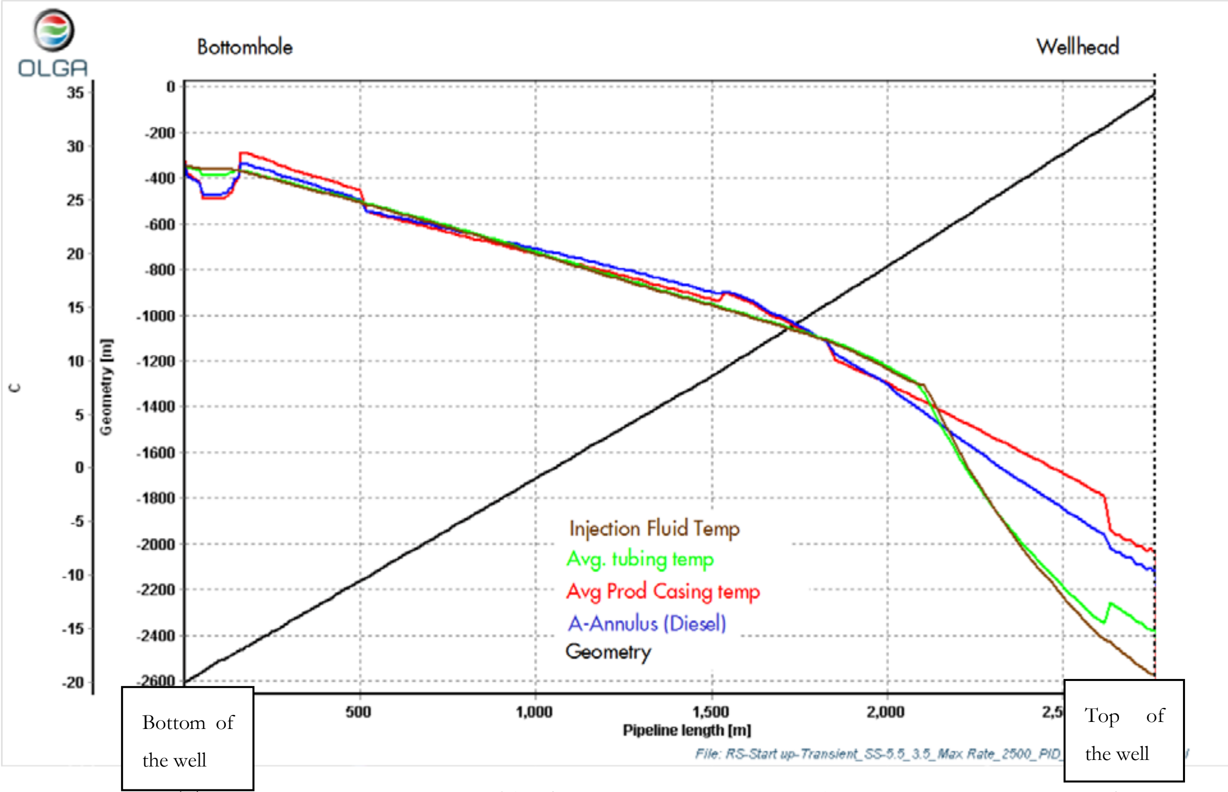


Figure 4-23: Traverse temperature profile design case: 13.5hr. 45bara WH pressure steady state (2500psia P reservoir)

In summary, the expected transient conditions are as follows:

Table 4-4: Results of transient calculations – design case (base oil in annulus)

	Design Case	Operating case
Steady State CO_2 manifold T, °C	3	-
Steady State manifold P, bara	120.2	-
Reservoir Pressure, psia	2500	2500
Steady State Conditions		
WHP, bara	45	115
WH temperature, °C	1	4
BH temperature, °C	17	20
Transient conditions		
Close in operation, h	2	0.5
Start Up operation, h	2	1
Coldest temperature (wellhead)		
Fluid CO_2, °C	-20	-17
Average tubing, °C	-15	-10
A annulus, °C	-11	-4
Production casing, °C	-10	-1

Strict operational procedures need to be implemented and adopted by the Goldeneye Well Operations Group to avoid extreme cooling of the well components due to temperature limitation of the well components.

4.5 SSSV testing

Inflow testing is an HSE requirement. For hydrocarbon wells, the frequency is normally every 6 months but needs to be defined for CO_2 injector wells in further phases of the project. The valve is normally tested by initially closing the well at the Xmas tree, then closing the SSSV and bleeding off the pressure to a given value. Then the WH pressure is monitored.

Bleeding off the WH pressure for SSSV testing should be done in a controlled manner. The report (UKCCS-KT-S7.18-Shell-005, 2011) highlights a methodology to test the SSSV.

The current view is that the WH pressure can be reduced quickly to 27bara and then it needs to be maintained at 27bara for approximately 24-hours to allow the vaporisation of the CO_2 in the tubing or the reduction of depth of the gas interface to the SSSV. There will be a continuous CO_2 mass rate coming out of the well. Once only gas is between the wellhead and the SSSV then the pressure can be bled off rapidly to 10bara.

In summary, the testing of the valve should be carried out very slowly allowing for the normal boiling of the CO_2 liquid into gas to minimize the lowest temperature which can be observed in the interface gas-liquid CO_2.

It is proposed to achieve required blowdown for SSSV testing using a dedicated facility that will re-use the existing vent system. The blowdown will be performed under automatic control to minimise low temperatures and liquid produced from the well.

4.6 Partial loss of control in CO_2 wells

There is an unlikely but potential scenario where a partial loss of control (e.g. a small wellhead leak may develop). In this case a surface leak will expel cold CO_2.

There is evidence in some CO_2 EOR projects during partial loss of control that ice forming at the leak point might reduce the consequences of the leak.

The influence of the low temperature into the different well elements will be variable depending on the leak rate, involved volume, time and the heat transfer from the surroundings of the well and internal elements of the well. One important factor is the ability of the SSSV to limit the amount of CO_2 to be released. This will be investigated during FEED.

There are different temperatures which can be considered as the lowest to be observed in the metal surface (Xmas tree and tubing in the top part of the well) leak scenario. The temperatures are mainly based on surface piping work.

Jet release of dense phase CO_2

In the event of a minor leak, commingling with air drives the temperature lower than the sublimation in the CO_2 jet. The jet temperature measured at Spadeadam experiments was -85°C. In the same experiments the metal temperature was recorded between -50°C to -60°C, although the duration of the experiment was relatively short.

CO_2 expansion to 1 bara

The sublimation temperature of the CO_2 at atmospheric conditions is -78.5°C. This temperature can be applied but heat transfer to solid CO_2 will be low, so the low temperature may not be realised in practise except in systems where the CO_2 snow will be finely dispersed in a highly turbulent stream.

CO_2 expansion to triple point

The triple point for pure CO_2 is defined at -56.6°C and 5.2 bara. Heat transfer between the walls and the dense phase CO_2 is very efficient. This temperature is similar to the recorded in the Spadeadam tests. It is recommended that -56.6°C should be used as the upper limit of the Minimum Metal Temperature (MMT) value for the project considering the limit heat transfer coefficient of the solids CO_2 subject to further validation.

The influence of a leak (size) in terms of temperature in different well elements will be calculated during early FEED in order to determine the lowest temperature rating to be installed in the Xmas tree and the tubing in the top of the well (down to the SSSV depth). Currently it is suggested that the new Xmas tree and the tubing between the Xmas tree and the SSSV are rated to -60°C (section 7.4). The other impact of the study would be to validate that the wellhead system and casing hanger (rated to -18°C) are capable of adequately dealing with the conditions of a CO_2 leak.

4.7 Total loss of control in CO_2 wells

Even though the potential of a total well control incident is extremely low, this eventuality must be considered. The strategy is clearly to prevent a blowout and much of the monitoring and corrective measures plans are aimed at identifying and remediating irregularities long before they can escalate to a blowout.

In a CO_2 well; with the rapid expansion of the CO_2, correspondingly rapid cooling will occur under a total loss of well control (blowout). Cooling can reach the point where solid dry ice particles form in the jet stream. After the loss of well control, the fluid accelerates until the pressure drop in the well matches the pressure drop between the reservoir and the pressure at the wellhead, limited by the sonic velocity.

The initial adiabatic expansion is instantaneous in its development, which is usually not expected by field workers. Often only a small volume of supercritical "liquid" CO_2 in the wellbore is enough to trigger the process, causing the well to blow out in the matter of seconds. Reaction time is minimal and some equipment, particularly manual BOPs and stab-in safety valve, cannot be installed and closed fast enough to avoid complete liquid expulsion from the well and total loss of pressure control (Skinner, 2003).

Although the risk of fire and explosions in a CO_2 blowout are negligible, it is replaced with the likelihood of extremely cold conditions caused by rapid CO_2 expansion. This can threaten the integrity of materials (brittle fracture) as well as threaten people directly by cold burns and frost bite. The extreme cold conditions also create danger from flying solids (ice and hydrates).

The extreme cold conditions in a blowout case will happen in the top of the well; their extension will depend on the CO_2 conditions from the reservoir (pressure and temperature of the CO_2 from the reservoir). For example in a tubing blowout scenario at 2500psia [172bara] reservoir pressure, the CO_2 would be -7°C shallower than 450m (1480ft) when the bottomhole temperature is similar than the reservoir temperature of 83°C. Assuming that the bottom hole temperature is 20°C then the well will be below -7°C in depth shallower than 780m (2560ft) for the same pressure conditions.

Emergency Response Plans will be developed during FEED for a loss of well control case.

5 Injecting into Existing Wells

The current upper completion was designed for hydrocarbon production. Changing to CO_2 injection will require a workover to install a single tapered tubing string in order to manage the CO_2 phase behaviour and to keep the integrity of the well.

5.1 Existing Well Integrity

Well integrity tests are carried out on an annual basis. All well integrity information is captured and stored in eWIMS under the responsibility of a Well Integrity Focal Point. Additionally, the control room monitors annulus pressure gauges on all wells continuously, with alarms at predetermined levels, and the data stored in RTMS (Real Time Management System).

An intervention campaign was carried out in 2012 and suspension plugs were set in all the wells. At the time some safety valve control line integrity issues were noted and corrective measures were required to some tree valves. In a number of wells the deep suspension plug was set above the downhole gauge thereby allowing the downhole pressure and temperature to be monitored.

The report (PCCS-05-PT-ZW-7180-00004 Well Integrity Assessment Report, 2014) presents a more detailed analysis of the well integrity in the existing Goldeneye wells.

5.2 Reasons for working over the existing producing wells

The five existing wells were evaluated to be used as CO_2 injection without any modification. However, due to potential integrity issues and CO_2 management is not possible to use the wells without any modification. A rig is required to carry out a workover of the upper completion by installing small tubing in order to manage the CO_2 expansion.

CO_2 phase behaviour

The combination of initial low reservoir pressures, circa 2650psia [183bara], large bore tubing 7" [178mm] and low arrival temperature of CO_2 to the platform 2.3-10.1°C make it impossible to maintain CO_2 above the saturation point when injecting CO_2 through the existing completion. By injecting in the existing wells, the CO_2 will expand and intersect the saturation line, generating low temperatures during the injection conditions (section 4.1.2). These extremely low temperatures caused by injecting CO_2 in the existing completions will create serious complications in terms of well design and operability as the temperature in the CO_2 will be below the lower threshold limit of some existing well equipment. The low temperature threshold of the existing completion is described below:

Table 5-1. Low temperature threshold of current completion equipment

Item of Equipment	Lower Temperature Limit	Limitations using the existing completion with free expansion of CO_2
Cameron Xmas tree block	-18°C	Predicted temperature under uncontrolled injection (-25°C) during transients is colder than low temperature threshold. Current Xmas Tree material can be up graded from 4140 low alloy steel to F6NM stainless steel which has a low

		temperature threshold of -60 °C.
Wellhead - Cameron 3 Stage Compact Spool	-18°C	Predicted temperature under uncontrolled CO_2 injection (-25°C) is colder than low temperature threshold. Compact spool is made from 4130 Low alloy steel and cannot be replaced without adding complexity to the workover operation.
Cameron Tubing Hanger	-18°C	Predicted temperature under uncontrolled CO_2 injection (-25°C) is colder than low temperature threshold. Tubing hanger material can be upgraded in line with the increased Xmas Tree specification.
Production casing 10 ¾" x 9 5/8"	-40°C	Temperature OK for steady state injection. Potential complicated operation to replace L80 casing in the upper section of the well.
Production Tubing 13Cr L80	-20 to -30°C (different source)	More investigation required to confirm the use of this for steady state production. Can be replaced with super 13Cr which has a low temperature threshold of -50°C
A- Annulus Fluid Sea Water	- 1.8°C	Predicted temperature (-25°C) is colder than low temperature threshold. Replace with Base Oil
TRSSSV (Current Supplier)	-7°C	Temperature OK for steady state injection at SSSV depth. Further qualification to be carried out in advance (one year) of workover operations commencing
TRSSSV Control Line Fluid	- 40°C	Temperature OK for steady state injection. Alternative control line fluid to -60°C available

For this case, there will be a requirement to change the shallow well equipment (Xmas tree, hangers, a portion of the tubing) for extremely low temperature service. There is also potential for integrity issues associated with freezing of annuli fluids in the wells.

Well Integrity

Should CO_2 be injected into the existing Goldeneye completions, a consequence of the resulting low temperatures (even managing the JT effect with small insert strings), is that the existing production tubing will contract to such an extent that the PBR shear ring, rated to 120,000 lbs has the potential to fail.

This being the case and given it is likely that regular movement of the PBR mandrel due to variations in downhole pressure and temperature will cause the PBR seals to fail. Containment of the CO_2 in the tubing will be lost above the packer.

This will also allow CO_2 to enter the A annulus and mix with water based completion brine. Should this be allowed to happen, the resultant formation of Carbonic Acid would cause an immediate and significant threat to the integrity of the production 9 5/8" [245mm] carbon steel casing.

There are issues with existing control line in two wells on the platform: GYA01 and GYA03. As such these wells cannot be used for long term CO_2 injection with the currently installed completion.

Others

- Removal of the perforated pup joint below the production packer and the screen hanger.
- Setting the new production packer deeper, to be in front of the Hidra seal. Ideally the production packer should be placed in front of the sealing formation. The current packer in the wells GYA01 and GYA05 are across of the bottom of the Chalk; during the workover operations there is an opportunity to set the production packer at the desired position.
- Optimise in-well surveillance.

5.3 CO_2 management and upper completion changes

A way of managing the potentially extremely low temperatures in the well during injection is by keeping the CO_2 stream in liquid phase at the wellhead, by increasing the required injection wellhead pressure above the saturation line.

Reduction in the expansion of the CO_2 can be achieved by extra pressure drop in the well. Options include the installation of a small diameter tubing creating back pressure by friction loss or a pressure drop in a device (downhole choke).

The Steady State calculations for this type of concept were presented in section 4.3 of this report and the transient calculations were summarised in section 4.4.

By performing a workover and changing some well elements the Goldeneye wells will be suited to inject CO_2. The low temperature is managed by installing a small size tubing and changing some well elements (described in sections 7) as follows:

Table 5-2: Low temperature threshold after workover during injection

Item of Equipment	Lower Temperature Limit	Limitations using the existing completion with free expansion of CO_2
Cameron Xmas tree block	-60°C	Current Xmas Tree material can be up graded from 4140 low alloy steel to F6NM stainless steel which has a low temperature threshold of -60 °C.

Wellhead - Cameron 3 Stage Compact Spool	-18°C	Compact spool is made from 4130 Low alloy steel and cannot be replaced without adding complexity to the workover operation. Operation procedures during normal transient events for the temperature to be above the threshold of this equipment. Under investigation for a leak scenario.
Cameron Tubing Hanger	-60°C	Tubing hanger material to be upgraded in line with the increased Xmas Tree specification.
Production casing 10 ¾" x 9 5/8"	-40°C	Temperature OK for steady state injection. Potential complicated operation to replace L80 casing in the upper section of the well.
Production Tubing 13Cr L80 and S13Cr	S13Cr -60°C 13Cr -20 to -30°C (different source)	Top of the well with S13Cr which has a low temperature threshold of -60°C
A- Annulus Fluid	__	An annulus fluid can be replaced with different fluids. Being investigated.
TRSSSV (Current Supplier)	-7°C	Temperature OK for steady state injection at SSSV depth. Further qualification to be carried out in advance (one year) of workover operations commencing
TRSSSV Control Line Fluid	__	Temperature OK for steady state injection. Alternative control line fluid to -60°C available

5.4 Suitability of the existing Lower Completion for CO_2 injection

5.4.1 Lower Completion Description in existing Goldeneye Wells

The five producers in Goldeneye have been completed with gravel pack. Oil industry practices for sand control requirement assessment and selection were used in the Goldeneye wells for the production phase.

The Lower completion in the Goldeneye wells was selected considering hydrocarbon production. The requirement for sand control was established considering the rock mechanics properties and the well characteristics. The selection of the sand control method was done considering the rock characteristics (e.g. grain size distribution), the understanding of the production phase and the evaluation of the different sand control techniques. Installation operations and long term reliability were also incorporated in the selection.

The Baker Alternate Pack system was chosen as the preferred lower completion. The following is a summary of the operations carried out during the installation of the lower completion.

- Drill to TD (8.5" [216mm] hole)
- Displaced to solids free mud
- Ran 7" [278mm] pre-drilled liner (ensure formation stability during the gravel pack operation) on drill pipe and washed down to the total depth
- Well displaced from mud (625pptf) to filtered completion brine (550pptf)
- Liner hanger set
- Ran 4" [102mm] Excluder 2000 screen and liner assembly
- Set the gravel pack packer
- Gravel pack 20/40 pumped until screen-out
- Spotted MudSOLV–U820 with enzymes treatment (chelating agent U820 attacking the $CaCO_3$ and enzymes attacking the starch)
- FIV closed
- Well displaced to filtered and inhibited seawater
- POOH gravel pack assembly
- Continue with the Upper Completion installation

The principal characteristics of the installed equipment are as follows:

- Pre-perforated Liner

It was used to ensure formation stability during the gravel pack operation. Size 7".

- Screens

The Excluder 2000 screen (Baker product) was installed in the well. This is premium downhole sand exclusion device. The size was 4" (3.548" [90mm] ID). Medium Wave was used with an average 210 microns weave.

- Gravel Pack

The gravel size used was 20/40. The medium diameter (D50) is approximately 730 microns.

Other components

- Other components:

FIV – Formation Isolation Valve

7" predrilled hanger and screen hanger

Perforated pup joint

Formations

Figure 2-1 shows the main stratigraphy for the Goldeneye area with the main characteristics of the individual formations.

Related to the lower completion: The main reservoir is the Captain D. Captain E is sand with relatively low permeability above the Captain D. The Rodby shale is the main seal above the Captain formation. There are some Marls above the Rodby called Hidra and Plenus Marl. The Plenus Marl is not present in all the Goldeneye producing wells.

Lower Completion description with respect of formation tops

The 9 5/8" [245mm] casing shoe was set at the Rodby shale (with the exception of GYA05 which was set at the Valhall formation). The bottom part of the Rodby and the Captain E layer was not isolated with the casing and as such it is part of the open system of the screens.

The top of the screens is installed above the 9 5/8" casing shoe. The top of the gravel pack is estimated to be above the top of the screens in 10-15ft [3-4.6m].

The screen hanger is either set at the Rodby formation or the Hydra formation.

The production packer is either set at the Chalk (GYA01 and GYA05) or within the Marls (GYA02S1, GYA03 and GYA04).

5.4.2 Injection Experience with Sand Control

Baker (the supplier of the screens) has indicated that the screen can be used for CO_2 injection. There will be no modifications required to use the Excluder2000 screen for injection purposes.

There is experience in water injection projects with similar kind of screens.

The main operating practice in water injection projects with sand control is safeguarding the injection system by having a tight control in the water specifications namely solids content and size. In some Shell projects the water specification calls for a maximum particle size of 5 microns. Normal practice is in the order of 17 microns considering only the gravel pack systems.

5.4.3 Lower Completion Under CCS

The principal question regarding the lower completion is its compatibility with CO_2 injection. This section is related to the containment of CO_2 in the lower completion (corrosion and lower part of the well barriers) and the reliability of the lower completion to sustain CO_2 long-term injection (erosion, plugging, flow reversing, etc.).

From the analysis to date, there is no reason to side-track the well and install a new lower completion. No showstopper has been identified from this analysis, which can jeopardize the CO_2 injection across the existing lower completion. There are some operational restrictions related to the characteristics of the CO_2 and some limitations related to the particles in the CO_2 but these are considered to be manageable.

5.4.3.1 Lower Completion Strings

There are two permanent lower completion strings. The retrieval of these strings is not considered feasible due to the gravel pack presence. In the case that the CO_2 cannot reliably be injected through the lower completion then a side-track will be required.

7" Pre-perforated string

The 7" [178mm] pre-perforated string consists of 7" 13Cr pre-perforated liner and Uniflex liner hanger. The hanger is set 160ft above the 9 5/8" casing shoe. This string was run in the well to ensure hole stability during the gravel pack operation.

No issues have been identified for the long term operation of the CCS in this string.

4" Screens string

The main elements of this string are A Baker Seal assembly, Baker SC-2R 9 5/8" [245mm] packer, FIV, & 4.00" [102mm] excluder screens. The screen implication under CCS is analysed in the next section.

Baker Seal Assembly

The Baker G22s seal assembly and 9 5/8" SC-2R screen hanger do not form part of the current well pressure containment. There is a perforated pup joint between the 9 5/8" production packer and the SC-2R screen hanger. This creates an open void that would originally have contained inhibited seawater. However it is likely that over the last six years or so of hydrocarbon production operations there has been some hydrocarbon ingress into the void. Given that Goldeneye hydrocarbons contain a small amount of CO_2 (0.4% mol). During the workover for the CCS operations, the 9 5/8" HHC production packer, the perforated pup joint and the Baker G22 seal assembly will all be recovered from the well along with the original production tubing. Should the well be worked over in 2014 for CCS operations the 9 5/8" HHC production packer, the perforated pup joint and the Baker G22 seal assembly will all be recovered from the well along with the original production tubing. After logging the 9 5/8" casing to check for corrosion damage and carrying out remedial work if required. The well will be re-completed "without" a perforated pup joint between the G22 seal assembly and 9 5/8" production packer. Effectively shielding the previously exposed 9 5/8" L80 production casing from exposure to CO_2.

Baker SC-2R packer

The Baker size 96B-60, SC-2R packer currently installed in Goldeneye wells were used for Gravel pack operations and to hang off the 4.00" Baker Excluder Screens. The SC-2R packer will not be removed from the well should the wells be worked over for CCS operations. The SC-2R packer is made of 13% chrome material and is considered to be suitable for use in a CO_2 environment provided that water and oxygen is not present in the feed gas and that there are no temperature excursions out with the packer operating envelope. The packer is rated to 7,500 psia [517bara] differential pressure from above and below and from 0°F – to 350°F (-18°C - 176°C). The Nitrile packing element is considered to be suitable for use in a dry CO_2 environment, and because of the deep packer setting depth there are no concerns over susceptibility to explosive decompression. Any failure of the SC-2R packer is mitigated by the fact that there will be a 9 5/8" production packer installed above the SC-2R packer should the well be worked over for CCS operations.

FIV

A 5.00" 15 lb/ft 13Cr Formation Isolation Valve (FIV) is installed as part of the lower completion in all of the Goldeneye wells. In the case of Goldeneye the main purpose of the FIV was to isolate the reservoir from the well bore post gravel pack operations, and to provide a positive mechanical barrier to flow when running the completion tubing. The FIV would then have been opened by application of pressure cycles down the production tubing. It is worth noting however, that remotely opening the FIV by application of pressure is a feature that can be utilised one time only, repeated application of tubing pressure will not operate the FIV once it has been opened. Subsequent manipulation of the FIV requires that a shifting tool be run on coiled tubing or wireline tractor to engage in a shifting profile inside the FIV. When the shifting tool is locked into the shifting profile a downward force of circa 1,200 lbs is required to move the FIV in to the closed position. It is not possible to close the FIV by application of pressure or if the FIV is exposed to large pressure differentials.

Should Goldeneye wells be worked over for CCS operations the FIV will not be removed from the well. The FIV is made from 13cr material and is considered to be compatible with CO_2 providing that there is no oxygen in the feed gas. The FIV in its current configuration simply becomes another section of 13Cr tubing and poses no threat to the future integrity of the well. The minimum ID through the FIV of 2.94" [74.7mm] although reduced when compared with the proposed CO_2 injection wells is sufficient to allow coiled tubing and 2.125" [53.98mm] O.D wireline logging tools to be run into the screen section.

Gravel Pack / Screens Analysis

The objective of this section is to document the requirements of a side-track because of potential incompatibility of the screens and gravel pack with the CO_2 injection. The top of the screens is above the 9 5/8" casing shoe (~40ft [12.2m]).

5.4.4 Material / Corrosion

The material of the steel installed in the lower completion is 13% Cr. This is valid for the 4" Screens and 7" Pre-perforated liner. Free water plus the CO_2 will lead to dissolution of CO_2, forming carbonic acid (H_2CO_3). This leads to corrosion of carbon steel. For 13%Cr this is not considered a corrosion threat.

Goldeneye reservoir is attached to a large aquifer. At least during the initial phase of injection the lower completion will be in contact with formation water; with time and CO_2 injection the presence of water will be decreasing with time as per the water will be displaced by the CO_2.

The presence of dissolved oxygen in the CO_2 and free formation water are critical given the current material installed in the lower completion. 13%Cr is not considered suitable at dissolved oxygen levels (in water) higher than 10ppb, failures of 13%Cr tubulars have been seen in very short timeframe in environments where oxygen level has not been controlled. This can lead to high pitting rates and stress corrosion cracking. To avoid side-tracks due to the material compatibility it is recommended to control the Oxygen to acceptable levels for the lower completion materials. This has been initially calculated at 1ppm Oxygen in the CO_2 stream.

5.4.5 Gravel Pack Design / Operations / Performance

The best indication of the performance of the lower completion is that sand has not been observed during the hydrocarbon production phase. In-line monitors are installed in the platform for each well and no sand production has been reported.

Most of the screen erosion failures in open hole gravel packs occur as a result of incomplete annulus pack. There are higher possibilities of solids passing through the screen as the fluid seeks the path of least resistance creating a 'hotspot' failure.

Gravel size was properly designed considering the Goldeneye sand characteristics in the Captain D. The selected gravel size was 20/40.

Gravel was placed around the screens and 7" pre perforated liner based on volumetric calculations during the operation. Theoretical calculations indicated that the top of the gravel is above the screens (6-21ft [1.8-6.4m] depending on well). Screen out was observed during the operation in all the wells with the exception of GYA02S1.

There is a drawdown limit during the production phase in GYA02S1 due to execution problems during the gravel pack operation (stop of injection and no screen-out). This limit is around 200psia [13.8bara]. This drawdown limitation will be evaluated at a later stage but the 200psia will probably be lifted as it applies for the production phase considering the gravel in the annular space between the hole and the screens. In the CCS, the CO_2 will be in contact first with the screen and then the gravel. The gravel does not play an important role as in the production phase. As such, this limitation can be lifted.

5.4.6 The Problem of losing integrity at the screens

One question that needs to be answered is: What would be the consequence of a screen failure under CO_2 injection? The principal consequence would be a serious reduction of injectivity in a relative short period of time because the gravel (from the gravel pack) can fill in the wellbore across the Captain D formation. This would happen during the non-Injection periods where the gravel can move freely inside the screen.

The reasons for the scenario and consequences above are:

- There is not a rat hole in the Goldeneye wells

  Total depth of the well is in the Captain D. Screens set close to the wells total depth. 60-70ft [18.3-21.3m] of true vertical depth has been completed in the Captain D

- Internal Volume of screens is small

  The internal diameter of the screens is 3.548" [90.1mm] ID. The volume inside the screens is only 0.0064m^3/m (0.052 bbl/ft).

- Gravel Volume

  The top of the screens extends above the top Captain D (63-207ft [19.2-63m]). There is gravel above the top of the screens (6-21ft [1.8-6.4m]).

  The volume of gravel is ~ 0.023 m^3/m – 0.187 bbl/ft3 (This considers a 8.5" [216mm] hole diameter – 7" [178mm] pre-perforated liner – and the screens OD). This value is 3.6 times the volume associated to the screens.

- Gravel will cover the wellbore over the Captain D interval in case of any failure

  Practically any screen failure will lead to the full coverage of the Captain D with gravel.

If the screen is covered with gravel then the pressure drop is significant to be able to inject through the linear proppant plug. Assuming that a 50 ft/5" [15.2m/127mm] screen is covered with proppant of a permeability of 100Darcy then the pressure drop through the proppant plug to be able to inject the minimum rate of the capture plant of 41 MMscfd (89.9 tonnes/h) would be in the order of 390 bara.

5.4.7 Plugging / Erosion

There are two effects to the lower completion, which are intimately related: plugging and erosion. Both issues depend mainly on particles in the injection fluid. In the case of plugging then the injected fluid can increase the speed through the open space of the system, which might lead to 'hotspot' erosion.

Even injecting under fracturing conditions, 17 microns (below) should be the maximum size of any particle dictated by limitations in the lower completion (5 microns is related to matrix conditions to avoid formation plugging, section 3.2.1).

5.4.7.1 Plugging of the Lower Completion

Plugging may reduce the injectivity through the screens and gravel with time.

In a production system the gravel will act as the main filter of the formation sand whilst the screen will act as the filter for the gravel. In general the gravel reduces the particles in contact with the screen and reduces the velocity at which particles contact the screen.

Very small particles can be accepted to avoid plugging at the screens and gravel pack. This is in line with the normal industry practice in water injection projects where sand control is installed; tightly control of the quality of the injection water is observed even injecting under fracturing conditions.

The internal volume of the screens across the Captain D reservoir is very small, from 0.31 to 0.55m^3 (1.9 – 3.4 bbl) (depending on the well). Practically there is no allowance for the accumulation of solids inside the screen.

Considering the dimensions of the currently installed equipment in Goldeneye wells and the accepted practice, the following calculations have been made:

Screen aperture dimension: 208 microns (Baker information)

Proppant Size: 20/40, D50 of proppant: 730 microns, gravel pore throat size (1/6): 120 microns

Formation Captain D D50: 230 microns, average pore throat size (1/6): 40 microns

- Particles larger than 70 microns plugs at the screen face (1/3 screen aperture)
- Particles larger than 40 microns plugs at the screen/proppant face (1/3 gravel)
- Particles between 17-40 microns bridges on formation sand face at interface with proppant, resulting in plugging of the gravel pack (1/7 & 1/3 gravel)

5.4.7.2 Erosion

Erosion is one of the most common mechanisms of screen failure. Screen erosion is a progressive failure that depends on fluid velocity, particle size and concentration and fluid properties. Erosion of the screen can be caused by the high downhole flow of fluid through the screens. The presence of solids will increase the erosion rate.

For erosion in the screens, it is normally accepted that particles above 30 microns will significantly increase the erosion rate. As such, particle size above 30 microns should be avoided.

The aperture velocity (velocity at the slots or open space of the screens has been calculated (assuming uniform distribution of the fluid in the screen, 10% of open space in the steel of the screens and considers only the length of the screen at the Captain D) for the different wells considering the downhole flow rate in the following picture.

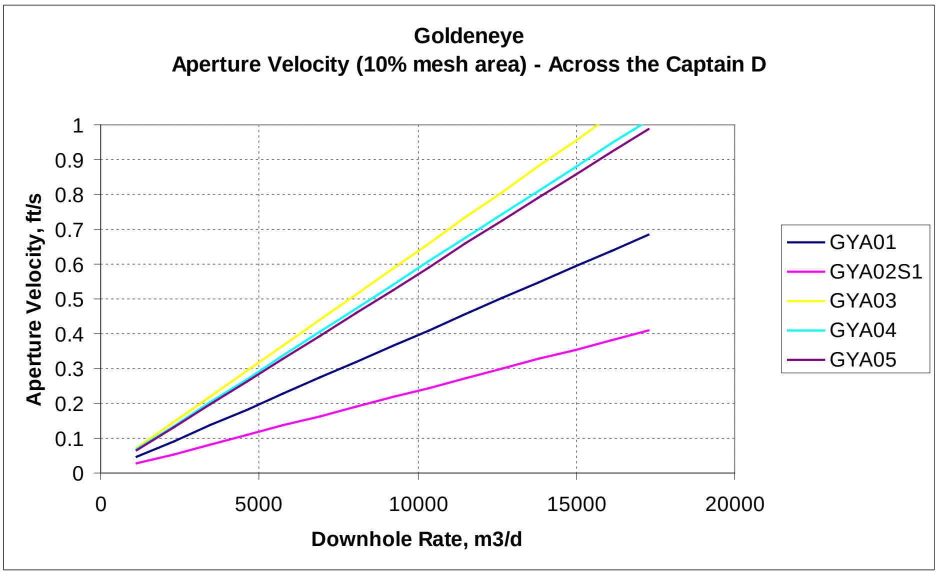


Figure 5-1: Aperture velocity in the screen assuming uniform distribution

The gas production at downhole conditions has been estimated using the individual allocated flow per well, information from the permanent downhole gauges as follows and the PVT properties of the Goldeneye gas as follows

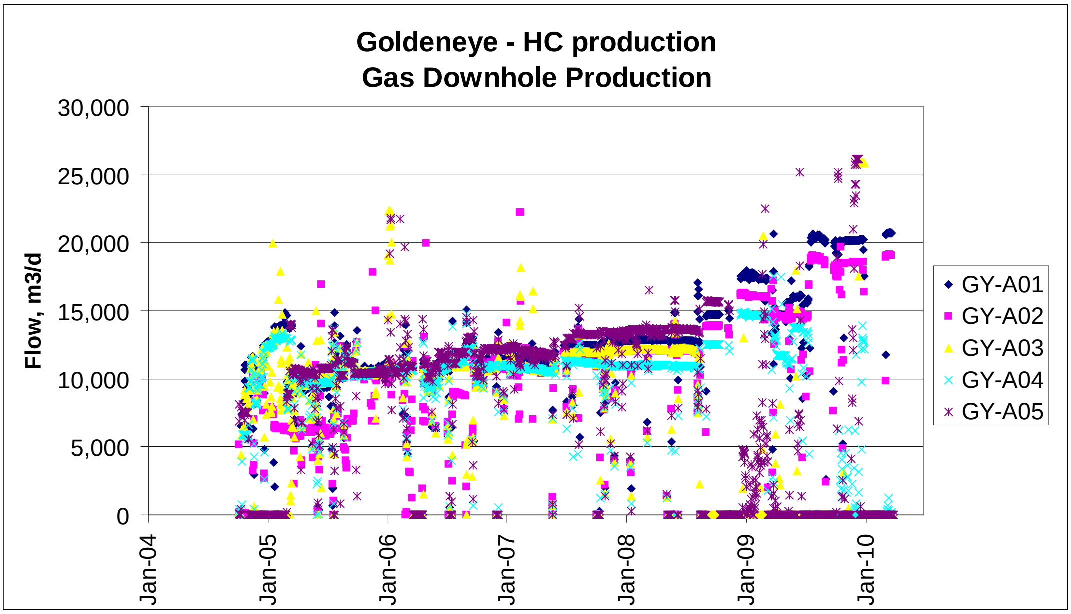


Figure 5-2: Downhole rate for the hydrocarbon phase

The aperture velocity at the screens is calculated and presented in Figure 5-3. The aperture velocity has been increasing with time (despite lower surface rates).

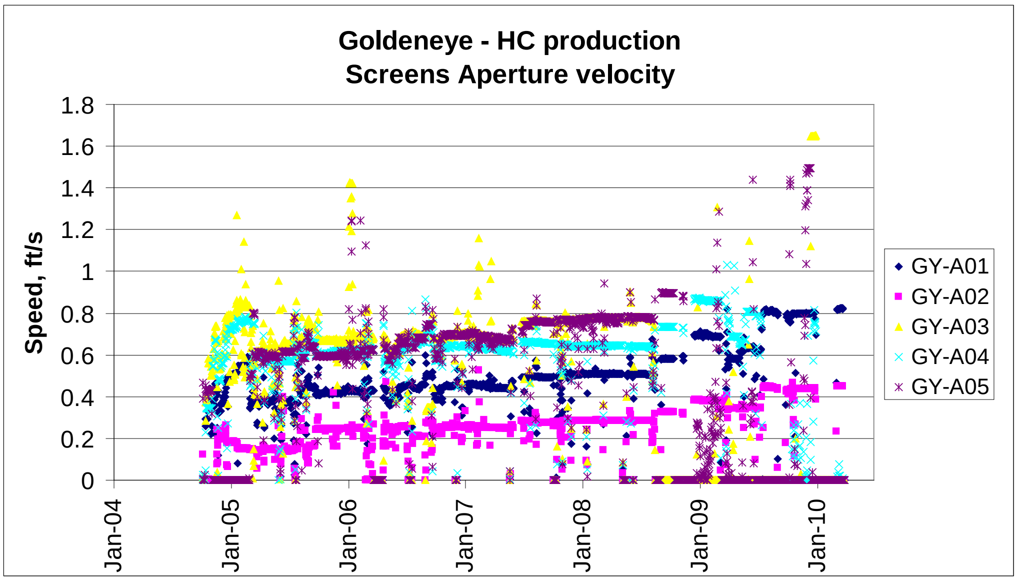


Figure 5-3: Aperture velocity in the hydrocarbon production phase (assumes uniform distribution)

At downhole conditions and under steady state conditions the CO_2 will be injected in single phase with low temperatures (20 to 40°C) and bottom hole pressures above the critical point. The bottom hole injection pressures range would be between 2,900psia [200bara] to 3,800psia [262bara] (250-400psia [17.2-27.6bara] above the reservoir pressure).

At the expected downhole pressure and temperature conditions the downhole flow rate of the CO_2 will depend mainly on the surface injection rate. The pressure and temperature will have a minor impact considering the steady state conditions of injection. This is due to the relatively stable density of the CO_2 at the bottom hole injection conditions (~920-940 kg/m^3).

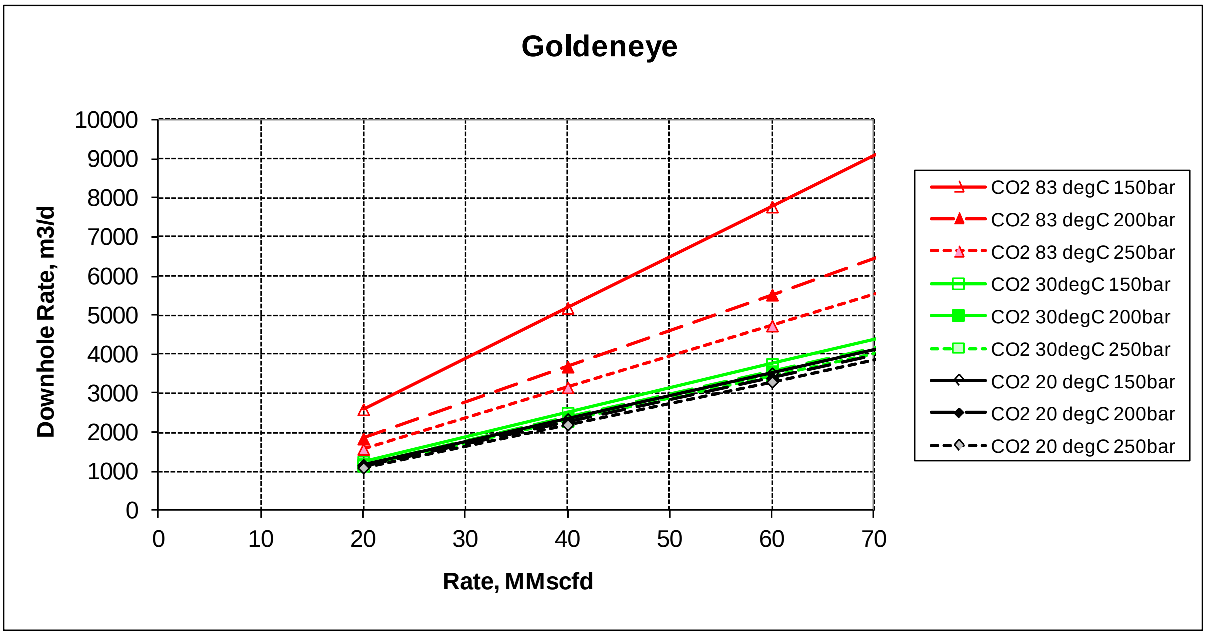


Figure 5-4: CO_2 downhole rate

The capacity of the capture pant is 63 MMscfd or 138.3 tonnes/h. The steady state (low temperature) downhole rate will be in the order of 3,580 m^3/d with small variations at different injection pressures. However, in the case that the temperature is much higher (around reservoir temperature 83°C) then the downhole rate will also be variable from 5,000 to 6,000 m^3/d.

Table 5-3: Bottomhole pressure and downhole rate relation for Goldeneye wells

63 MMscfd Injection rate 138.3 tonnes/h	BH Pressure	Downhole	Screen Aperture velocity *, ft/s		
	bara	m^3/d	GYA01	GYA02S1	GYA03, 04, 05
Steady State (20-40°C)	150-250	~3,580	0.14	0.09	0.20-0.23
Res. Temperature (~83°C)	200	5,800	0.23	0.14	0.33-0.37
	262	5,000	0.20	0.12	0.28-0.32

During the injection process the CO_2 will contact first the screens (Excluder 2000). As such, the restrictions for stand-alone screens (SAS) related to erosion should be applied (instead of the gravel pack restrictions). Liquid limitations (instead of gas limitations) should be used as the density of the CO_2 at bottom hole injection conditions will be very high ~920-940 kg/m^3. For liquid flow the normally accepted industry velocity is 1 ft/s for production conditions.

It is clear that the aperture velocity (assuming uniform flow) during the hydrocarbon production phase is much higher than the expected velocity during the CO_2 injection case. In both cases the aperture velocity is below the threshold velocity. In CO_2 it is more variable depending on the downhole conditions of pressure and temperature because of the CO_2 variation with these properties.

However, the aperture velocity assumes uniform flow through the screens. Under production conditions this can be considered a good approach due to the presence of gravel distributing the flow – the flow is dispersed and distributed across the screen, which reduces the creation of hot spots. Under injection conditions the CO_2 will be first in contact with the screen increasing the susceptibility to get plugged. If a large area of the screen is plugged or flow is going through a short interval such as fractures, the erosion rate can be considerably higher creating a hot spot injection.

Even considering a reduction of the maximum aperture velocity from 1 ft/s to 0.25 ft/s (quarter of the maximum recommended velocity) due to the reasons described above there will not be any limitations in the wells with respect to the downhole injection velocity of the CO_2 under steady state conditions.

The main consequences of the calculations are in the well start up procedure. Start-up procedures in the wells should be developed to be able to cope with the Joule Thomson effect in the top of the well (rapid injection) and to avoid very high downhole rates created by high rates at warm CO_2 conditions at the screen level after some shut-in period.

5.4.8 Flow Reversal (applicable to existing wells)

The wells were completed with a screen and gravel pack in the lower completion. By design the gravel pack was the main filter to avoid sand production from the wells, and was designed considering the grain size in Goldeneye and the recognized oil industry design criteria.

In a production system the gravel will act as the main filter of the formation sand whilst the screen will act as the filter for the gravel. In general, the gravel limits the size of the particles that come in contact with the screen and reduces the velocity at which particles contact the screen.

By reversing the flow, from the production hydrocarbon production phase to the CO_2 injection phase, there might be some re-accommodation of fines currently embedded in the gravel pack under hydrocarbon production.

It is likely that sand failure has occurred in Goldeneye due to the level of depletion combined with the rock strength. Fines have been trapped / embedded in the gravel pack, which is designed for this function. The well productivity has not decreased with time.

Upon flow reversal the formation fines currently embedded in the gravel pack could be mobilized and could then become trapped against the formation (like an external filter cake) and would then create an additional pressure drop thereby reducing the injectivity in the well.

The effect of this pressure drop is considered low due to the following reasons:

- Well productivity stable with time.

  Indication of a limited volume of fines being trapped with time as the pressure drop in the wellbore has been stable.

- Captain D is well sorted sandstone

  Completed in the top of the D sand where the sand sorting is better. Fines percentage in the Captain D is very small

- Gravel pack designed considering the general criteria in the oil industry
- Industry experience in underground storage with sand control

This low risk can be further reduced with an injectivity test. However, the value of information of carrying an injectivity test just for this cause is low, as the risk is considered manageable.

The mitigation were this issue to occur is to drill a side-track and to install a new gravel pack. This avoids the trapping of solids in the lower completion during the production phase.

5.4.9 Other considerations under fracturing conditions

The simulations above show that injecting the CO_2 under fracturing conditions will not pose a problem in reservoir terms. The fracture lengths are not long and even in the worst case scenario the frac will be constrained in the lower part of the Rodby.

From the well design / operations perspective the consequences of injecting under fracturing conditions are as follows:

5.4.9.1 Filtration

In the event of injection under fracturing conditions, the CO_2 quality specification in terms of suspended solids may be relaxed. The injectivity is not affected as the fracture will grow longer.

In the case of Goldeneye, the lower completion, screens and gravel pack, also imply limitations in terms of CO_2 quality due to erosion / plugging.

To avoid formation impairment under matrix conditions, the CO_2 should be filtrated to 5 microns whilst to avoid blocking of the screens / gravel pack then the CO_2 should be filtrated to 17 microns to avoid lower completion erosion and plugging.

The initial period of CO_2 injection will be most likely under matrix condition and 5 microns filtration will be required. In the case of confirming injection under fracturing conditions, the CO_2 quality might be relaxed to higher value but not above 17 microns in size due to the lower completion restrictions (erosion / plugging). An evaluation should be done to examine the predicted length of the fracture once the solids content is known.

In any case, under matrix or under fracturing conditions, the filtration is required and as such there will not be a big cost difference in terms of the operation.

5.4.9.2 Impact on packer position

One of the concerns is related to the well integrity in the case of fracturing conditions.

The simulations suggested that the created fracture, even in the worst case scenario, will remain into the Rodby not breaking into the Hidra marl.

Ideally, the production packer should be placed above the predicted top of the fracture in CO_2 injection. This reduce the risk of CO_2 entering the A-annulus in the well in the case of radial degradation of the cement and casing during the injection life. The planned production packer setting depth is currently at the Hidra level above the Rodby, as such there is not a problem.

The theoretical top of the cement is in the Chalk (1500ft [457m] AHD above the casing shoe) which is well above the predicted top of the fracture. The production casing at the Hidra formation (part of the primary) seal is also cemented. This will avoid CO_2 communication with the A to B annulus even by a complete axial degradation of the cement at the Rodby level.

Considering the above even injecting under fracturing conditions will not pose an integrity risk to the well.

5.4.9.3 Lower completion impact

There might be limitations related to the lower completions (screens / gravel) currently installed in the well. Two issues have been identified: Displacement of gravel into the fracture and 'Hot Spot' erosion.

Displacement of gravel into the fracture

The drag forces of the injected CO_2 might displace the gravel into the propagating fracture, leaving the space between the hole and the screens without gravel. Some operators have expressed concerns about formation sand entering the wellbore reducing the general injectivity as the gravel is no longer between the hole and the screens. However, there is uncertainty in the industry as to whether it is possible that displacement of gravel into the frac could possibly occur given the mitigating elements described below:

- Experience gained from working with water injector wells in other developments demonstrates that not all injection wells experience gravel displacement into the propagating fracture.
- The drag forces of CO_2 compared with pure water are much less due to the lower viscosity of the CO_2. Viscosity of water at 20°C is in the order of 0.99cP and CO_2 would be in the order of 0.10cP.
- An "alternate gravel pack" system was used in the Goldeneye wells. Good packing of the gravel during the initial completion operation was achieved.
- The 7" [178mm] pre-perforated liner used in the alternate packing system will help with distributing the CO_2 over the screens in the event of fracturing conditions developing.

Even in the event that gravel is displaced into the propagating fracture, the amount of solids from the formation passing the screens and depositing/filling the wellbore will be limited. The premium screens have an aperture of 208 microns, which is similar to the average particle diameter (d50) of the formation sand in the Captain D (d50=230 microns). In addition, the uniformity coefficient of the formation sand was estimated at 2.5. In summary, the screens were also purpose designed for the formation sand and in the event that the gravel is displaced into the propagating frac, then the lower completion will behave as a Stand Alone Screen, which is an acceptable completion situation.

'Hot Spot' erosion

'Hot spot' erosion of the screens is a potential problem under fracturing conditions as the injected CO_2 is not uniformly distributed over the screens. Under fracturing conditions, the CO_2 will be injected trough the two wings of the created frac. The CO_2 velocities can be extremely high and screen erosion might occur, or 'hot spot' erosion. Holes can develop in the screen, resulting in loss of screen integrity and subsequent injectivity problems.

The downhole rate of the CO_2 will determine the expected velocity across the open space of the screens – called aperture velocity. Holes can be developed in the screen, resulting in loss of screen integrity and a subsequent injectivity problem as gravel and or formation sand is allowed to flow inside the screens. If fracturing is suspected, the recommendation is to control the injection in order to obtain an aperture velocity across the screens of 1 ft/s [0.305 m/s].

This has not been observed in water injector wells under fracturing conditions with sand control equipment. It might be possible that the injected fluid is somehow uniformly distributed at the screen level, limiting the hot spot erosion' and then channelized in the annulus space between the screen and the hole into the fractures. The other possibility is to have multiple fractures at the wellbore level helping to have a more uniform distribution of the injected fluid at the screen level.

5.4.9.4 Screen Erosion Test

From the previous analysis there are some potential issues with the screens related to discrete fracturing of the reservoir. Erosion depends mainly on aperture velocity, solids contents and size and type of the solids. .A screen erosion test was considered to be carried out during FEED to confirm the suitability of the screen at high rate liquid CO_2.

However, the test will not be carried out due to the following reasons:

- The CO_2 is planned to be filtered to 5 microns it is envisaged that the remaining smaller particles would not erode the screens (not enough mass to create damage).
- Filtration of the CO_2 will reduce the formation of 'hot spot' erosion in the screens distributing the injected fluid across the screens more uniformly
- The created frac in soft rocks create multiple fracs enhancing permeability instead of discrete fracs (two wings).
- The normally accepted value of aperture velocity of 1 ft/s is for liquids. This 1 ft/s value has been determined for liquid (water) production conditions through SAS

  It is possible that the upper limit of the aperture velocity is higher than the used value of 1 ft/s due to the lower viscosity of the CO_2 compared to water, though the density of the water and CO_2 are similar at injection conditions in Goldeneye.

5.5 Re-Completion Options for managing the CO_2 properties

Reduction in the expansion of the CO_2 can be achieved by extra pressure drop in the well. Options include the installation of a small diameter tubing creating back pressure by friction loss or a pressure drop in a device (downhole choke).

During the Longannet-Goldeneye CCS study the preferred method was the use of small diameter tubing over a pressure drop caused by a downhole device. This is still supported for the Peterhead Goldeneye CCS.

6 Conceptual Upper Completion Selection

Workover or replacement of the upper completion will be required in the existing wells (Section 5.2). The lower completion (sand exclusion) will be left in place as there is not a requirement to perform side-tracks (section 5.4). Fit for purpose completion design that addresses the issues of well bore freezing, material selection and tubing contraction will be installed.

Small diameter tubing is currently the preferred option as discussed in this chapter.

6.1 Available options

The available completion options can be divided in two options:

- Friction dominated concept: small tubing, insert string, dual completion and concentric strings.
- Downhole choke

They can be visualised as follows, Figure 6-1:

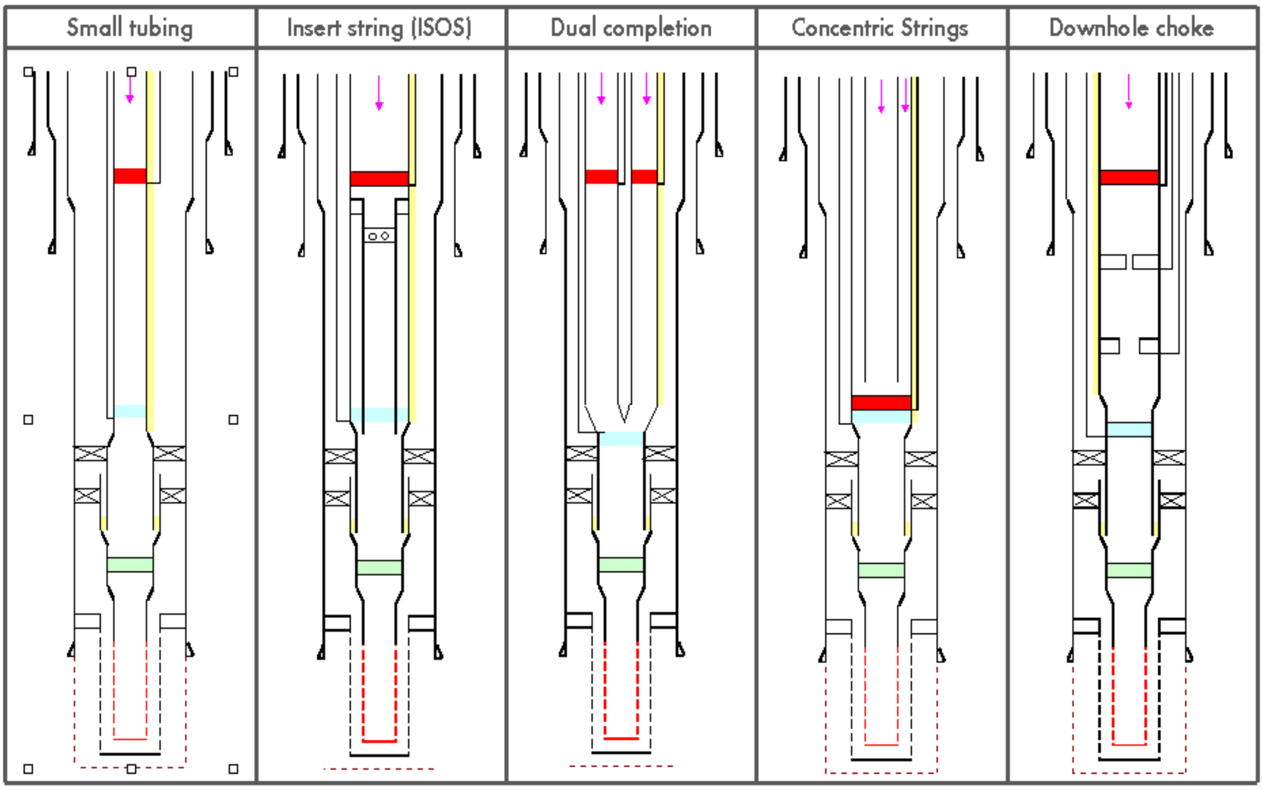


Figure 6-1: Completion Concepts (for injecting in single phase CO_2)

The different completion options were evaluated / compared considering:

- Well design: Installation ease, normal practice in the industry and North Sea, reliability of the solution and optimisation opportunities
- Injection Flexibility: Management of injection requirement, flexible injection from the minimum to the maximum of the CCP.
- Well Integrity: Maintain well integrity, carry out prescribed integrity tests
- In- Well monitoring: ability to install and have reliable data from PDGs, DTS, etc.
- Well Intervention: Easiness to intervene the well (wireline, coil tubing)
- Life Cycle Cost: CAPEX, OPEX and abandonment cost

6.1.1 Single Tapered Tubing

Under this scenario a single tapered tubing is used in the Goldeneye wells to create the required delta pressure to keep the CO_2 in single phase at the wellhead. A minimum rate is imposed per well.

The combination of wells will be able to meet the CO_2 rates from the capture plant (section 8 of this report).

Table 6-1: Single tapered tubing. Advantages and disadvantages [1'' = 25.4mm]

Well Design	(+) Simple and Standard completion (+) Simple Wellhead

	Different tubing sizes required (4 ½" & 3 ½") (-) Small tubing. 3 ½" is not a common size in the North Sea, but plenty of onshore experience
Injection Flexibility	One string per well (+) Combination of wells provide the required injection conditions for the life cycle of the project. (-) Limited range of injection conditions – depends on tubing size (-) Minimum rate required
Well Integrity	(+) SSSV depth (+) corrosion logs possible (+) Pressure Integrity Test is possible. Special tool might me required due to the small tubing size.
In-well monitoring	(+) Normal installation. Enough annular space for in-well tools
Well Intervention	(+) Standard. Limited ID depending on tubing size and FIV (2.94")
Life Cycle Cost	As a minimum 2 injectors required and 1 back up (+) simple integrity workover (if required) (+) no late workover required to meet CCP rates

6.1.2 Insert String

The installation of an insert or velocity string below the SSSV will introduce the required frictional pressure losses into the injection system, thus maintaining the supplied CO_2 above the saturation line in the dense liquid phase.

The main advantage of the system is the ability to install the SSSV at a depth similar to currently installed SSV in the existing wells.

Table 6-2: Insert string. Advantages and disadvantages [1" = 25.4mm]

Well Design	(-) Medium complexity. Experience in the gas industry with velocity strings (+) Simple wellhead Different tubing sizes required (4 ½" & 3 ½") in the insert string Hanger inside the tubing is critical. Pressure sealing required in the top of the insert string. Extra stresses created by this configuration. (-) Unable to fix leaking in the completion tubing
Injection Flexibility	One string per well. A workover to remove the insert string might be executed to expand the operating envelope of the well once the reservoir pressure increases. More applicable to expansion storage projects. (+) Combination of wells provide the required injection conditions for the life cycle of the project. (-) Limited range of injection conditions – depends on tubing size

	(-) Minimum rate required (+) Optimisation: Install SSD in the insert string or perforate the insert string to increase the operating envelope
Well Integrity	(-) Severe vibration expected. Innes tubing not in tension, free-hanging. Tubing integrity can be lost by the excessive moving and banging into the outer tubing. This can be considered as a showstopper for this kind of completion. (+) SSSV depth (-) corrosion logs not possible in the outer string (the tubing providing CO_2 containment in the tubing). Corrosion log possible in the inner string. (-) Pressure Integrity Test not possible in all the tubing length (where the insert string is positioned)
In-well monitoring	(-) PDG and DTS in the outside tubing. External reading of temperature might not be representative due to the distance to the injected CO_2.
Well Intervention	(+) Doable. Limited ID depending on tubing size and FIV (2.94")
Life Cycle Cost	As a minimum 2 injectors required and 1 back up (-) integrity workover (if required) (+) no late workover required to meet CCP rates (-) Slightly more expensive abandonment

6.1.3 Dual Completion

Each tubing in a dual completion well will introduce the required frictional losses into the injection system. A minimum rate in each string should be maintained to avoid CO_2 flashing in the top of the well.

The advantage of the system is to expand the operating envelope per well by injecting in one or both tubings at the same time. Dual 3 ½" [89mm] 13Cr tubing and 2 7/8" [73mm] 13Cr tubing will meet forecasted injection volumes of CO_2 with the use of fewer wells. DTS, PDGs would be able to be incorporated in the well.

Table 6-3: Dual completion. Advantages and disadvantages [1" = 25.4mm]

Well Design	(-) High complexity. Practically no experience in the North Sea with dual strings (-) Dual Xmas tree required. Long lead item. Goldeneye wellhead is not designed for a dual Xmas tree and tubing hanger. A new build Xmas tree is likely to be required. (-) limited combinations in the dual tubings (2 x 2 7/8", 2 x 3 ½" (?) and 2 7/8" – 31/2") Y-tool preferred over dual packer (stronger completion) (-) impact of tubing stresses when injecting down in the a single string (-) Mechanical barriers to be recovered through small tubing. (-) Congested well bay (dual wellhead and dual flowlines)
Injection Flexibility	Two string per well.

	(+) Increase flexibility per well (3 different injection sizes: tubing1, tubing 2, tubing 1 + 2) (-) Minimum rate required (-) More difficult inflow calculation. Total capacity of the well should be approximately ~ 0.85 of the tubing 1 + tubing 2 due to inflow restrictions. (-) Congested well bay
Well Integrity	(+) SSSV depth. 2 SSSV per well operating independently. (+) PIT per string can be execute (+) Corrosion log possible (-) Multiple/complex leak paths In case of a tubing failure, injection might continue in the well by isolating the leaking string.
In-well monitoring	(-) Limited space in the A-annulus. Ability to install devices depends on the completion size (-) PDG below Y-tool. DTS possible in one or both strings depending on size. Number of penetration increase in the wellhead – confirmation required of it doability
Well Intervention	(+) Doable. Limited ID depending on tubing size and FIV (2.94") (+) 2 strings to get access to the wellbore. However, Y-tool will cancel this option (only one string normally has access to the wellbore)
Life Cycle Cost	As a minimum 2 injectors required and 1 back up. Not possible to meet injection expectations with only one well (-) Very expensive initial workover (-) Expensive integrity workover (if required) (+) no late workover required to meet CCP rates (-) Expensive abandonment

6.1.4 Concentric Completion

The inner string will be run inside the outer tubing string. The advantage of the system is the ability to change injection from the inner tubing to the outer tubing or both expanding the operating envelope per well.

Table 6-4: Concentric completion. Advantages and disadvantages [1" = 25.4mm]

Well Design	(-) High complexity completion. No major experience in the hydrocarbon industry with concentric completions (-) Special dual wellhead required (Horizontal tree). Special design required and long lead item. The current wellhead at Goldeneye is not suitable for running a concentric completion from surface to require depth. Different tubing sizes required (4 ½" & 3 ½") in the inner string (-) Unable to fix leaking in the completion tubing (-) Deep set SSSV

	(-) Lots of modifications required to standard practice in the oil industry.
Injection Flexibility	Two string per well. (+) Increase flexibility per well (3 different injection sizes: inner, annulus between inner and outer tubing, both)) (-) Minimum rate required (-) More difficult inflow calculation. Total capacity of the well should be approximately ~ 0.85 of the tubing 1 + tubing 2 due to inflow restrictions. (-) Congested well bay
Well Integrity	(-) Severe vibration expected. Inner tubing not in tension, free-hanging. Tubing integrity can be lost by the excessive moving and banging into the outer tubing. This can be considered as a showstopper for this kind of completion. (-) SSSV depth. The SSSV can be installed below the inner string. No remedial activities in the SSSV due to the ID restriction of the concentric string. The valve is set very deep with larger CO_2 inventory. (-) corrosion logs not possible in the outer string (the tubing providing CO_2 containment in the tubing). Corrosion log possible in the inner string. (-) Pressure Integrity Test not possible in all the tubing length (where the insert string is positioned)
In-well monitoring	(+) Existing completion (7") with PDG and cable. (-) PDG and DTS in the outside tubing. External reading of temperature might not be representative due to the distance to the injected CO_2.
Well Intervention	(+) Doable. Limited ID depending on tubing size and FIV (2.94")
Life Cycle Cost	As a minimum 2 injectors required and 1 back up (-) Expensive integrity workover (if required) (+) no late workover required to meet CCP rates (-) Expensive abandonment

6.1.5 Downhole choke

Under this scenario, there is a downhole choke which creates the delta pressure required to manage the CO_2 in dense phase along the well.

Normally the downhole should be installed at a depth where no phase changes can occur to avoid vibration and cavitation. For Goldeneye wells this is deep in the well.

Table 6-5: Downhole choke. Advantages and disadvantages [1'' = 25.4mm]

Well Design	Smart application. (-) Control line requirement. Proven technology for inflow control modifications where small delta P is required. In our case high delta P is required across the device. (-) Wellhead with more penetrations (special hangers or modifications required).

	(+) Normal tubing size of the North Sea Small chokes required (6 – 11 /64th in) (-) Prone to choke erosion and plugging Placement not very critical of the choke. In the dense phase (deep in the well). Optimisation: Installation of multiple downholes chokes
Injection Flexibility	One string per well. Large pressure drop in the downhole chokes. (-) Big change of operating range with small changes in size diameter. (-) Pressure and Temperature drop across the choke might increase the potential for hydrate deposition. Late injection will not require downhole chokes as the reservoir pressure will increase.
Well Integrity	(+) Standard SSSV Corrosion log and PIT possible above the choke. Not possible below the choke.
In-well monitoring	Same than single tapered tubing (+) Normal installation. Enough annular space for in-well tools
Well Intervention	(-) Partial. No access to the reservoir. Access below the choke will depend on choke type.
Life Cycle Cost	As a minimum 2 injectors required and 1 back up (+) no late workover required to meet CCP rates (-)High chance of well activities to change downhole chokes (-) Smart application. Expensive workover

6.2 Comparison of Completion Concepts - Discussion

The initial installation of the single tapered completion option is the simplest and most robust. The other systems present extra challenges / cost in comparison to the single tapered completion, specially related to the wellhead and Xmas tree system (for dual completion and concentric string). For the insert sting option, the inner string hanger is critical to the CO_2 management. The downhole choke would require special control lines depending on the number of chokes to be installed.

For all the friction dominated completions there will be a minimum rate. The injection flexibility in the single tapered system can be managed with the number of wells. The other friction dominated systems present more flexibility in terms of number of injection strings per well. However, in the single tapered completion, the combination of different wells with different injection characteristics will be able to accommodate from the minimum and maximum rates of the capture plant during the life cycle of the well. The downhole choke option can have issues regarding well envelopes in case of erosion/abrasion in the choke (small changes in choke size can have significant changes in pressure drop and hence unpredictable envelopes).

The well integrity management in single completion is ideal; position of the different safety devices is robust. The insert string and concentric string options presents an integrity problem related to the vibration of the inner string when injecting high velocity CO_2 require to obtain the friction. The position of the SSSV in the concentric string is critical as the depth would be very close to the reservoir. The number of potential leak paths is high for dual completions. Pressure integrity test in the downhole choke would be challenging below the valve in case of not able to retrieve the choke.

The single completion tubing and the downhole choke completion present the best option for in-well monitoring. The in-well monitoring is not ideal in the insert and concentric strings as the temperature information is from the outer tubing string. Depending on tubing size there might not be enough space for accommodating all the required devices in a dual completion.

The well intervention for the friction dominated completion concepts is similar. Dual completion options presents a slightly less than ideal conditions due to the intervention being possible in only one string if Y-tool options is selected. In the single tapered tubing the only restriction for well intervention is related to the tubing size (potential landing nipples) and deep in the well by the FIV. The downhole choke option will have limitations in easy intervention as the restriction would require to be removed prior to any intervention.

A traffic light can be used to visualise the advantages and disadvantages of the different completion systems. Green represents ideal conditions and red represent a major concern of the option.

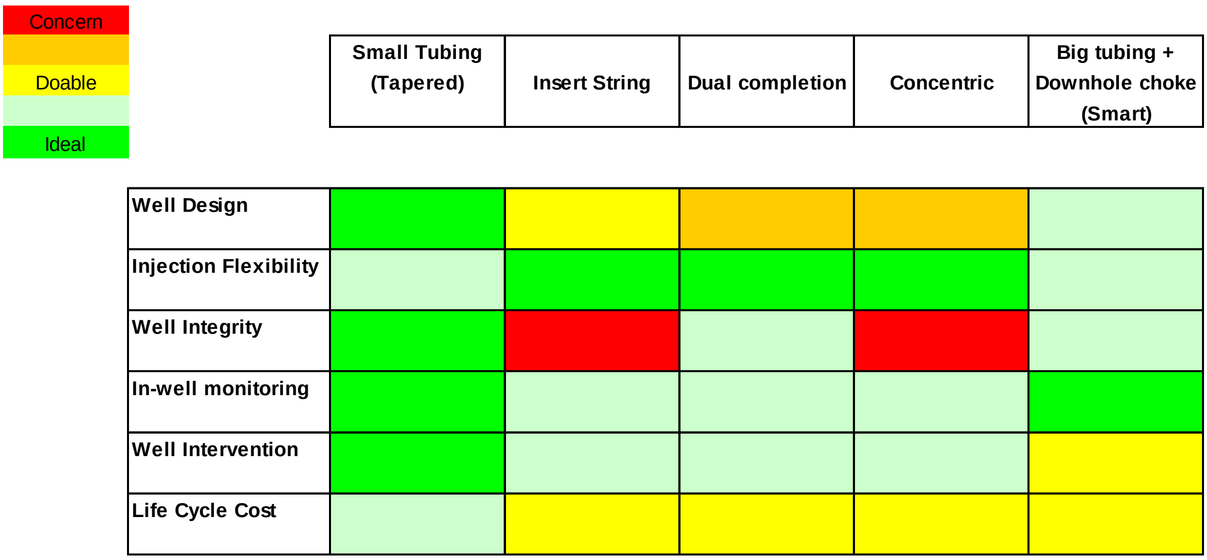


Figure 6-2: Traffic light for completion concepts

Considering the discussion above the single tapered completion is selected.

7 Well Construction Elements

The report (PCCS-05-PT-ZW-7180-00002 Conceptual Completion & Well Intervention Design Report, 2014) contains more information on the selected option. This section is an abstract of it and presents the important messages from it.

The change of use of Goldeneye wells from hydrocarbon production to CO_2 injection has been checked against the existing well design notably in the following areas

- materials (metallurgy and elastomers)
- casing design
- cement
- pressure management

- temperature

Limitations of the different well components were investigated for the expected well conditions under CO_2 injection. The Christmas tree and the tubing hanger will be replaced in the workover with units having a lower minimum temperature rating. All completion equipment (i.e. attached to the tubing string) will have 13Cr or S13Cr equivalent metallurgy and will have working pressures in excess of the expected final well pressures.

It is proposed to standardise the top (from surface down to the SSSV) and the bottom (up to the PDG) of the upper completion for the CO_2 injection. The planned well design for CCS is shown in Figure 7-1.

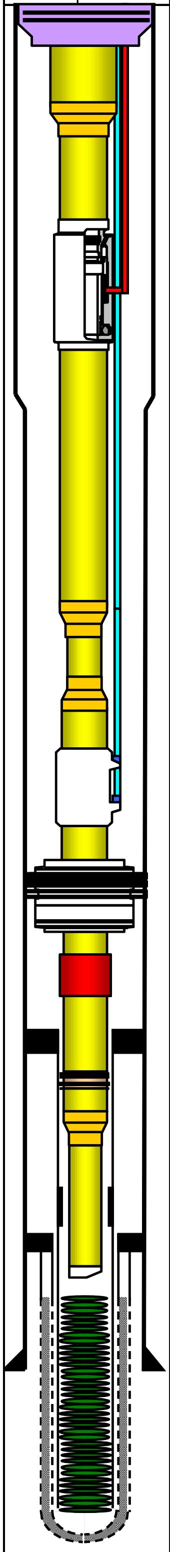
GYA 01 Proposed	Depth MD (ft)	Description of Item	ID (Inches)	Drift (Inches)
	79	Tubing Hanger	6.169	
		7.00 29# Tubing 13Cr/S13Cr	6.184	6.059
	139	XO 7.00" 29# x 4 1/2" 12.6#	3.958	3.833
		4 1/2" 12.6# Tubing 13Cr/S13Cr	3.958	3.833
	2500	SCTRSSSV 4 1/2" 13cr	3.813	
	3130	Casing XO 10 3/4" x 9 5/8"		
	6800	XO 4 1/2" 12.6# x 3 1/2"	2.922	
		3 1/2" Tubing	2.922	
	8430	X/O/Wire Finder Trip Sub 3 1/2" x 4 1/2" 12.6#	2.992	2.787
	8536	4 1/2" PDGM for PDG + DTS	3.958	3.833
		4 1/2" 12.6 # Tubing	3.958	3.833
	8596	9 5/8" x 4 1/2" Packer	3.818	
		4 1/2" Circulating/Pressure Relief Device	3.958	3.833
		4 1/2" Tubing		
	8696	Baker SC-2R packer/screen hanger 13Cr (existing)		
		G22 Seal Assembly	3.958	3.833
	8650	XO 4 1/2" 12.6# x 2 7/8" 6.4# FJ Tubing	2.441	2.347
	8755	Schlumberger FIV (existing)	2.94"	
	8850	2 7/8" Mule Shoe		
	8952	Top of 4.00" Screens (existing)	3.548	

Figure 7-1: Proposed general well schematic [1" = 25.4mm]

7.1 Well Materials

7.1.1 Carbon Steel

CO_2 in the presence of water will lead to dissolution of CO_2, forming carbonic acid (H_2CO_3). This will lead to corrosion of carbon steel. The typical CO_2 corrosion rate for carbon steel in contact with water (wet conditions) will be in the order of 10 mm/yr.

Normally, in carbon steel tubulars, CO_2 corrosion is mitigated by proper control of the water content of the CO_2 to avoid formation of free water and to prevent wet excursions. The water content in the CO_2 is specified as below 20 ppmW.

Available low temperature Charpy impact test results of the present carbon steel production casing show that toughness is adequate down to -40°C.

7.1.2 13Cr steel

Even under wet conditions, CO_2 corrosion is not a threat for 13Cr steel under typical Goldeneye injection conditions.

13Cr is susceptible to localised corrosion in wet conditions when O_2 is present. A limit of 1 ppmv for O_2 in the CO_2, corresponding to a concentration O_2 dissolved in water below 10 ppb (by mass); will prevent such corrosion from occurring.

In case O_2 is present at higher levels than the specified, it is not a corrosion threat without the presence of free water and it might be expected that the O_2 would be consumed, at least in part, by the corrosion of carbon steel upstream of the wells (pipelines).

The generally accepted low temperature limit for 13Cr steel is from -10 to-30°C (depending on manufacturer) and for Super 13Cr it is estimated at -50°C. In any case, impact testing of 13Cr or Super 13Cr tubing will be required for equipment to be run in the wells (especially in the top part of the wells, where extreme low temperatures are expected during transient conditions and loss of well control scenarios).

7.1.3 Elastomers

Elastomers can also absorb gas and suffer explosive decompression when pressure is reduced. Any elastomers to be in contact with CO_2 have been checked for compatibility. Where needed these elastomers will be changed out.

7.2 Conductor and Casing strings

7.2.1 30" Conductor

The 30" [762mm] conductor was driven 200' [61m] into the seabed to 750ft [229m].

From 2010 PEC (Pulsed Eddy Curent) corrosion surveys, the carbon steel conductors look as though they may be falling into the higher corrosion rate category. However, load calculations for the worst case corrosion rate (0.5 mm/yr over a 25 yr period) conclude that the existing Goldeneye 30" conductors are fit for the expected load cases for the duration of the extended field life. The 30" conductor will not be in direct contact with CO_2.

7.2.2 20" x 13 3/8" Surface Casing

The first casing string set inside the conductor was a 20" x 13 3/8" [508 x 340mm] taper string set at around 4150ft. The 20" casing features a 1" (25 mm) wall thickness. The 20" casing was cemented to seabed. The surface casing will not be in contact with the injected CO_2.

The 30" conductor and 20" x 13 3/8" casing are freestanding and independent of one another. The 20" surface casing takes all the well loading and does not transfer the load to the 30" conductor.

Goldeneye Platform wells have been analysed with WellCat software. The analysis also models the conditions of CO_2 injection. PEC corrosion surveys were run on both the conductor and the surface casing. There are indications that corrosion rates on both strings are relatively high. A special case has been worked up to simulate high 20" corrosion rates. Using the "high" corrosion rate of 0.5 mm/yr and a 25 year life span - both worst cases, the conclusion is that the pipe is still fit for purpose - Safety Factor of 2.4 for axial loading. Furthermore, at high corrosion rate the 20" casing still has several years' life left beyond the 25 year life span. Hence, the Goldeneye 20" casing will be good for the expected load cases for the duration of the extended field life. It follows that no load transfer to the conductor is expected.

7.2.3 10 ¾ x 9 5/8" Production Casing

The second casing string or 10 ¾" x 9 5/8" [273 x 245mm] taper production casing was set at the bottom of the Rodby formation. This casing was cemented to approximately 1500ft [457m] AH above from the casing shoe.

The position of the production packer in the current completion and the new completion for CO_2 injection will be similar but deeper. The production packer in the injectors should be positioned in the wells across the Hidra marl, considered part of the reservoir seal.

The current corrosion of the production casing above the existing packer is practically nil as the completion fluid used in the A annulus was inhibited seawater installed during the completion operations. The production casing above the production packer is not expected to be exposed to free water and CO_2 during the injection phase. Internally, the 13Cr tubing prevents contact with the injected fluid.

Underneath the production packer, a section of production casing has been exposed for the period of ~6 years to the hydrocarbon production environment (natural gas with 0.3% CO_2). This probably led to some corrosion of the casing but the magnitude of attack is unknown. As an estimate of maximum corrosion, assuming wetting for the full 6 years of field production, the corrosion loss would be of the order of 6 yrs x 0.1 mm/y = 0.6 mm. In view of protection by $FeCO_3$ scale and a much shorter wetting period (wells production was closed in only after the presence of formation water), the actual wall loss is probably less and of therefore of little significance.

The same section of the production casing (underneath the production packer), the carbon steel casing would be in contact with the injected fluid. Under normal injection conditions the CO_2 corrosion rate is controlled by the water content in the CO_2. However, during non-injection periods, water from the aquifer might initially come back into the well leading to presence of water and CO_2, which can result in high corrosion rates (10 mm/yr). A corrosion allowance of 2 mm is adequate to make the carbon steel reach the design life of 20 years. Based on an estimated typical CO_2 corrosion rate of 10 mm/y, it would take a little more than 1 year of wet exposure to corrode through the ½" thickness of the casing. This implies that to avoid the casing corroding through, wet exposure to the CO_2 environment needs to be limited to less than 1 year in total over the required life of the casing.

Even in the scenario of having casing failure and axial cement degradation, the risk of leaking CO_2 is very low. This is based on the estimated matrix properties and the absence of fractures at the Hidra level. Additionally, during most of the injection period, the pressure of the CO_2 downhole will be lower than the hydrostatic pressure. As such, there is no reason to plan a side-track for the potential of out of zone injection of the CO_2 as the marls above the Rodby also present adequate sealing characteristics.

In the current well completion, a perforated pup joint is present below the production packer and the top of the screen hanger; this section creates a dead volume (stagnant) between the tubing and the production casing. CO_2 fluid could find its way through the perforated pup and contact the carbon steel production casing in the dead area between tubing and casing and potentially cause high levels of corrosion in the casing. Although this section is below the existing production packer, it is recommended to remove the perforated tubing section during the workover operations to give more protection to the casing and to be able to run the new production casing across the Hidra.

Due to injection of cold CO_2, the load cases are driven towards tensile loading due to thermal contraction.

Normal CS ("LT0") is adequate down to 0°C. For lower temperatures, carbon steel should be impact tested. Available certificates that supported the quality of the installed production casing were analysed and recorded Charpy values at different temperatures demonstrating adequate toughness down to -40°C, well below the worst case lowest casing temperature on injection conditions. If such information would not have been available, then the next step would be to assess the suitability based on the design code used, the materials specification and the wall thickness.

7.3 Cement

This section is a summary of the Chapter 4 and Appendices 4 & 5 of the report (PCCS-05-PT-ZW-7180-00002 Conceptual Completion and Well Intervention Design Report, 2014) where detail analysis on the cement is presented.

The primary cement sheath of the production casing is a barrier to capture the CO_2 downhole in the well. The cement used in the cementation is normal Portland class G cement.

The theoretical top of the cement (TOC) in the B-annulus between 9 5/8" [245mm] production casing and the 10 ¾" [273mm] hole has been estimated for all five wells during the cementing operations. The cement column from the 9 5/8in casing shoe to the theoretical TOC is calculated at 1,500ft [457m] AHD above the shoe, well above the formation seals of the reservoir. Cement evaluation logs were not run during the drilling phase of the wells, but are scheduled for the workover operations.

The cement is considered of good quality, based on well operation records. The historical records show that the casing integrity is good as a successful pressure test was achieved after bumping the top of the cement plug during the production casing section. The historical records of top well annuli pressures also show that no anomalies have been reported in the B annulus pressures during the production history of Goldeneye.

The distance between the currently installed production packer and the theoretical TOC is between 1,190 and 1,351ft [363m and 412m] AHD depending on the well. The cement is covering the primary seal formations (Rodby and Hidra) in all five wells up into the Chalk formation. This is enough cement height to ensure a barrier in the B annulus above the production packer.

Given that the TOC is theoretical, it is recommended to run a cement evaluation tool to better assess the condition of the cement in the B-annulus during the proposed workovers of the upper completion.

The long term effect of CO_2 on cement has been investigated. Cement degradation by CO_2 in the form of carbonic acid is a process that produces an insoluble precipitate that slows degradation. Several recently published papers examine various experiments or case studies that examine the potential degradation of Portland based cements when exposed to high CO_2 environments.

Degradation rates are proportional to temperature, pressure and the square root of time. From literature, estimates for cement degradation vary from 0.05 m in 10,000 years to 12.36 m in 10,000 years. Goldeneye conditions ~2m in 10,000 years.

Diana software, a specialist mechanical cement model has been run to ascertain the thermal effects of CO_2 injection on Goldeneye. The injection model simulates the thermal effects on the mechanics of the system (casing / formation / cement). Diana results indicate that the remaining integrity of the cement is sufficient for CO_2 injection in the Goldeneye Platform wells. The remaining capacity of the cement sheath for various simulated operational scenarios is sufficient for CO_2 injection in the Goldeneye Platform wells.

7.4 Surface Trees and Wellheads

The Goldeneye Xmas tree and wellhead is suited to CO_2 injection for the specified steady state operating parameters, but only for temperatures down to -18°C. The main issue is that 410 stainless steel has a very low Charpy impact value that could generate cracking.

The 7" [245mm] tubing hanger is designed for temperature class S,T,U,V (-18 to 121°C) and the 10¾" [273mm] casing hanger is designed for temperature class P (-18 to 82°C).

Due to low transient temperatures (in the order of -20°C in the CO_2) during opening and closing of the wells and even lower temperatures which might be encountered in leak scenarios (-56°C), surface trees and tubing hangers will be changed to low temperature compatible equipment. These well items will be manufactured as long lead time items and installed as part of the workover operations.

The current Cameron Xmas tree class U and tubing hanger is rated to -18°C will be changed to a lower temperature rating equipment. The material can be upgraded from the current 4140 low alloy steel to a maximum F6NM stainless steel which has a low temperature threshold of -60°C. The details of the new Xmas tree will be defined during FEED.

The casing hanger is designed to -18°C; the fluid transient temperature during well operations in the design case is -20°C in the top of the well and -15°C average tubing temperature (in the normal operating case is estimated at -17°C and -10°C respectively). As the casing hangers are not in direct contact with the CO_2, the expected temperature is above the average tubing temperature. For this case there is no requirement to change out the casing hanger during the well activities.

Under uncontrolled leaks, the temperature of the CO_2 might get very cold (metal temperatures estimated at the triple point -56°C and jet temperatures of around -80°C). The Xmas tree and the tubing hanger can be changed to consider this possibility. However, some well elements cannot be changed. Detailed thermal simulations of the wellhead/Xmas tree system will be done in the next phase to evaluate the extension of the low temperature during leak scenarios for evaluating the suitability of the system.

7.5 Upper Completion

The existing upper Completion will be retrieved. A new upper completion will be installed.

All completion equipment will have 13Cr equivalent metallurgy and will have working pressures in excess of the expected final well pressures.

As part of the workover operations, the tubing hanger and tree will be installed and pressure tested. This will then allow for final well hook up and flow of CO_2 through the pipeline to the platform.

7.5.1 Tubing

Re-completion of the wells will incorporate changing out of the 7" [245mm] tubing to a smaller size. As pressure and CO_2 rates will vary during the duration of the project, the injection rates will be accommodated by different tubing sizes in the injection wells - low rates with smaller tubing and higher rates with larger tubing, considering the well deviation.

The tubing sizes will be optimised in the later stages of the project when more information is available, especially regarding the reservoir pressure, injection rates and powerplant power generation cycles.

The intention is to standardise the top and bottom part of the upper completion. Currently the preferred tubing size in the top of the well (from the wellhead to the SSSV) is 4½" [114mm].

The upper completion tubing will be a 13Cr steel tubing material to provide protection of CO_2 corrosion. The current view is to install Super 13Cr tubing in the top of the well (from wellhead to SSSV) which gives more resistance to lower temperatures than 13Cr. For both materials 13Cr and Super 13Cr, impact testing will be required. In the case 13Cr is resistant to temperatures below the minimum expected CO_2 temperature in the top of the well, 13Cr might be used instead of the Super 13Cr.

Tubing hanger material can be upgraded in line with the increased Xmas tree specification.

7.5.2 SSSV and control lines

The SSSV is required to seal off the flow of CO_2 from the wellbore should surface flow control systems fail for any reason. The Goldeneye SSSV is currently set at 2,500 ft [762m].

The SSSV will be positioned deep enough in the well so as to be unaffected by the same failure mechanisms that can compromise surface ESD systems, and shallow enough that closure times are not compromised by having to overcome high hydrostatic pressures in the control line and to facilitate the testing of the valve by reducing the volume to bleed off. Other factors determining the final setting depth for the SSSV are the maximum depth that hydrates form and uncontrolled flow conditions.

The temperature rating of the SSSV is -7°C. In the transient design case, the -7°C is observed at around 1,500 ft [457m]. The sub-zero temperature in the well is at 1,950ft [594m] depth. The current depth of the valve was selected according to the hydrate deposition curve in the hydrocarbon phase, a situation which cannot be disregarded during CO_2 injection as the wells will be completed initially in the hydrocarbon leg and the presence of a hydrocarbon bank displaced by the CO_2. Uncontrolled flow calculation indicates a temperature of -7°C at ~2500ft [].

The final depth of the SSSV will be defined at a later stage, but the depth will be similar to the current setting depth in the production wells.

The current control line fluid (Castrol Brayco Micronic SV/3) is currently qualified for operations covering the temperature range of -40°C to 200°C (-40°F to 392°F), Castrol Brayco SV/3 has a low pour (<-50°C (<-58°F)) point making it suitable for operations in low ambient temperatures.

Testing of the SSSV is predicted to be a lengthy operation (24-40hours) especially when the tubing between the valve and the wellhead is filled with dense CO_2. In order to minimize this time the top of the tubing is proposed to be 4 ½in tubing rather than 5½" [140mm].

7.5.3 Production Packer

For CO_2 injection operations, a standard AHC hydraulically set production packer made from 13Cr material is considered to be suitable. The packer includes a one-piece mandrel and seal bore, reducing potential leak paths.

For CO_2 injection a HNBR (Hydrogenated Nitrile Butadiene Rubber) elastomer-sealing element will be used. HNBR, also known as "Highly Saturated Nitrile" (HSN), is a special class of nitrile rubber that has been hydrogenated to increase saturation of the butadiene segment of the carbon polymer backbone. Subsequent improvements to the material properties, over that of a nitrile rubber (NBR), include greater thermal stability, broader chemical resistance, and greater tensile strength. HNBR can be formulated to meet application temperatures ranging between -50°C and 165ºC (-58°F-329°F).

The packer should be positioned in the well across the Hidra marl, considered part of the reservoir seal. The screen hanger is either set at the Rodby formation or the Hidra formation. Currently, the packers in GYA01 and GYA05 are set in the Chalk group. In these wells the plan is to install the packer deeper in the Hidra formation. The existing packers in GYA02S1, GYA03 and GYA04 are currently set in the Hidra formation. The final placement of the new packers for CCS operations within the Hidra will depend on the status of the production casing at the moment of the installation. A production casing evaluation tool will be run during the workover of the wells to assess the condition of the production casing strings and optimise the position of the packer.

7.5.4 In-well monitoring

The completions will feature permanent temperature and pressure monitoring gauges. There will also be a distributed temperature sensor - a fibre optic system taking temperatures every one metre in the well. In the event of a tubing leak, the distributed temperature readings would facilitate the location of the leak. It will also give a better understanding of the temperature calculations in a CO_2 well.

Pressure and temperature modelling suggests that the BHT (Bottom Hole Temperature) is likely to be in the region of 17°C-35°C [63- 95°F]. Currently, the pressure gauges are routinely calibrated for temperatures in the range 25°C-150°C [65°F-302°F]. Therefore further qualification of the NPQG NET system will be required before it can be used on Goldeneye for CCS operations.

7.6 Lower Completion

Aspects related to the lower completion are discussed in section 5 of this report.

The lower completion will be left in place during the workover activities. The lower completion of the wells consists of open hole gravel packs including premium screens and pre-drilled liners – alternate path system. Main elements are: 7" [245mm] pre-drilled liner across the reservoir, 4" [102mm] screens, 20/40 gravel between the hole and the screens and FIV 2.94" [74.7mm] ID. The top of the screens are at the Hidra marl level.

As CO_2 will be injected into the well it is imperative not to block or damage the lower completion.

From the analysis to date, there is no reason to side-track the wells and to install a new lower completion. The lower completion will not be changed during workover operations.

7.7 Other well elements

7.7.1 Pressure containment between the lower completion (top of the screens) and upper completion (tail pipe)

There is the possibility to install a seal assembly in the tail pipe to seal off the casing between the production packer and the SC-2R screen hanger. This will reduce the exposure of the 9 5/8in casing to CO_2 to below the SC-2R packer. A closed space with stagnant fluid between the packer and the SC-2R packer (top of the screens) will be created. The main concern is that the cold injection of CO_2 will contract the fluid installed in this confined space leading to vacuum conditions, generating loads to the casing (collapse), tubing (burst) and packer (high differential pressure) which might jeopardise the well integrity with time.

The other option is to stab the tail pipe into the SC-2R without the sealing mechanism. In this case more casing is exposed to CO_2. There will not be a closed space between the packer and the top of the screens. This option is preferred as the production packer will be installed at the Hidra level, which is part of the CO_2 subsurface seal and it is expected that dry CO_2 will displace and evaporate water from the wellbore, reducing the corrosion rate of the production casing.

This will be explored in detail in the FEED phase. The options to install pressure relief valves in a close system will also be investigated.

7.7.2 Packer fluid

The fluid left in the A annulus for Goldeneye Wells should have the following characteristics:

- Avoid/minimize Corrosion in tubing/production casing. Compatibility with tubing and casing.
- The rheological properties of the packer fluid should be stable during injection period. It should have a low freezing point to cope with the well transient condition and should be stable in terms of phase envelope.
- The fluid should be solid free.
- Have the ability to monitor the annuli pressure over time. Positive pressure at all times.

Alternatives are (i) base oil designed for low temperature with a Nitrogen cushion which manages the thermal expansion of the base oil or (ii) water based systems with freezing point depressor (e.g. methanol) or (iii) water based brine.

Sleipner used a Calcium Bromide ($CaBr_2$) brine in the A-annulus to avoid freezing of the annulus with a freezing point of -46°C (Baklid, 1996).

Annular fluids will be selected during FEED

8 Number of Wells

The Peterhead CCS bid submission, made in mid-2012, included ***four*** wells converted for injection/monitoring, with the recommendation to decide the way forward of the fifth well during further stages of the project.

The number of require injector wells depends mainly on the injection estimates (reservoir pressure and injectivity), capture plant rates, CO_2 management, monitoring requirements and life cycle risk management.

The well(s) not converted for CO_2 injection will also need to be considered for the Peterhead project. Options included are to complete as an injector/monitor or to abandon the well.

The installation of small bore tubing in the wells limits the operating envelope of each well. In order to accommodate the range of injection rates at the different reservoir pressures during the injection life, each well will be completed with a different tubing size/configuration tailored to a specific rate range. The wells will then have overlapping operating envelopes and any rates specified in the integrated consortium basis-for-design will then be achievable through the choice of a specific combination of wells.

The five existing wells will be recompleted for the Peterhead CCS project. Two wells are the absolute minimum injectors for the life cycle of the project. Two additional wells are required: a back-up and a monitoring well. The fifth well in the platform will be re-completed based upon a project decision.

8.1 Minimum number of injection wells

In order to manage the CO_2 behaviour of the CO_2 and avoid integrity problems in the wells created by freezing, each well will have a limitation in terms of minimum rate dictated by a minimum of 50 bara of wellhead pressure. The maximum rate of a well will be dictated by the maximum available injection pressure, estimated at 115bara at the wellhead dictated by the MAOP of the offshore pipeline.

The injection range per well at a given reservoir pressure can be shifted by changing the length of the section of the different tubing sizes (4 ½" and 3 ½" [144mm and 89mm] tubing). However, the range per well cannot be expanded. The completion sizing also considers overlapping of well envelopes to give flexibility and redundancy in the system for a given arrival injection rate. At a given arrival rate different combinations will add flexibility to the system. The aim is to minimise the number of wells within the overall well restrictions.

The frequent opening-up and closing-in events should be avoided to limit the stresses in the well (temperature reduction during short periods of time) and to reduce the operation intensity in the wells. As such, line packing will be important to reduce the level of well operations.

The "Organ Pipes" were developed to integrate all the selection considerations,

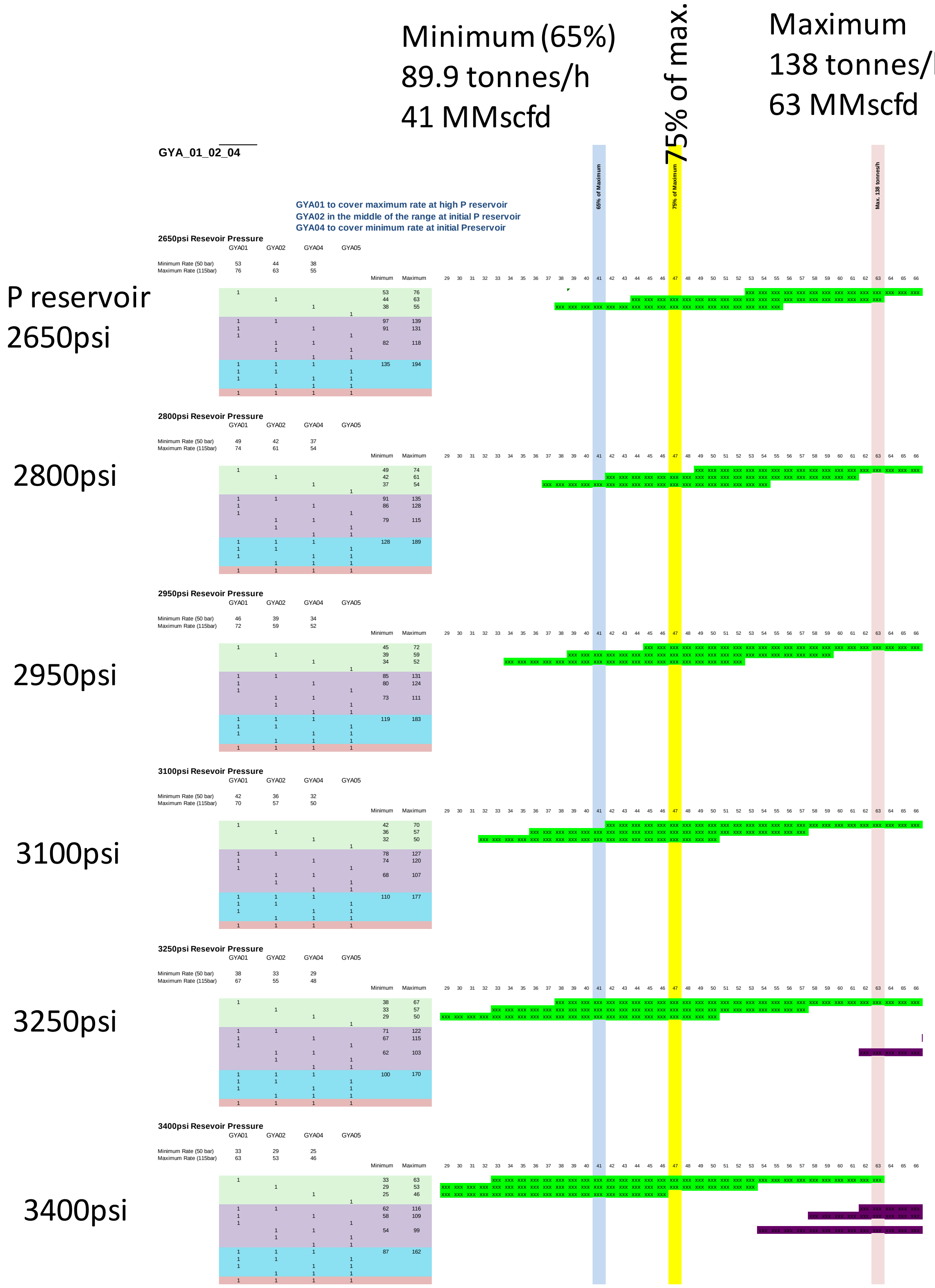


Figure 8-1: Organ Pipe for Goldeneye project.

A single well will not be able to inject from the minimum to the maximum CO_2 injection rate for the duration of the project. This is due to the limited injection envelope per well and the increase in reservoir pressure with injected CO_2.

The range of injection from the minimum to the maximum of the capture plant at the predicted reservoir pressure evolution can theoretically be achieved with only two wells. A small well might likely be injecting during the initial years of the project when the reservoir pressure is relatively low. A big well will likely be used when the reservoir pressure exceeds 2950psia [203bara].

In case of unforeseen problems in a particular injector well, it is proposed to complete an additional or back-up well as a CO_2 injector to the number of wells required to cover the injection range. As such, at least ***three*** wells are required to be completed as injectors (observed in the "Organ Pipe").

8.2 Monitoring well

The monitoring well (GYA-03) is selected considering the MMV requirements of the project. The main objective of the well is to monitor reservoir pressure and monitor the CO_2 breakthrough in the well in order to calibrate models.

The project could choose to reduce the number of wells recompleted by one, using the monitoring well as a late life backup. This is challenging from a monitoring perspective as it is estimated that the CO_2 breakthrough will take place in the monitoring well at around 10Mt of injection, near the end of injection.

The completion of the monitoring well will be similar to the injector wells. For the identification of the CO_2 breakthrough additional downhole gauges will be included (different in density between water and CO_2).

8.3 Fifth well

If the project chose to re-complete only four wells the utilisation of the fifth well would have to be addressed. The fifth well will be handed over to the storage license as part of the sale and purchase agreement of the assets from the current production license.

This fifth well cannot be left under the current condition for the duration of the Peterhead CCS project due to the risk of failure. In addition the industry is moving away from long term suspension:

> The Oil & Gas UK well suspension and abandonment guidelines July 2012, and the Internal Shell suspension guidelines do not determine the maximum amount of time that the well can be suspended. Steer from the Well Integrity TA2 in the U.K. indicates that the industry in general and DECC (the regulator) are moving towards the reduction of suspended wells in the near future. It is likely that new guidelines will suggest a maximum time that the well can be left suspended. This will limit the ability in Peterhead CCS to leave the wells with the current suspension.

There are therefore only two options for the additional well: re-completion as injector/monitor; or abandonment.

It is preferred to re-complete the well as injector/monitor instead of abandoning for the following reasons:

- Increases the flexibility of the wells to be able to inject at varying CO_2 rates from the capture plant
- Increases the resilience of the whole system to external influences – such as nearby injection by a third party

- Mitigates against possible well failure.
- Improve reservoir monitoring. The well can be used to assess the effects of the CO_2 injection with respect to the development of the reservoir pressure and the saturation changes in different parts of the reservoir.
- The ability to show conformance between the predicted and actual CO_2 movement within the reservoir is increased by using the backup high rate well for monitoring early in the life of the store. This might reduce the time between *site closure* and *transfer of responsibility* as per the EU directive on CCS.
- While expansion potential is out of scope for the project – retaining all injection wells does increase the ability of the platform to accommodate increased injection rates in the future.

As part of the drilling programme, it will be important to determine the value of each well should side-tracking be required owing to work over challenges. This will allow the drilling team to determine the walk away point from any well.

All wells will need to be abandoned at the end of the useful life of the platform.

9 Other Production Technology Aspects

9.1 Maximum Bottom Hole Injection Pressure

In an isothermal injection case the maximum bottom hole injection pressure corresponds to the minimum stress at the primary seal including a safety margin. The injection pressure must not exceed 5860psia @ bottom hole under isothermal conditions with no safety factor (lowest recorded minimum gradient at the Goldeneye area).

Injecting a cold fluid will change the minimum stress condition around the wellbore.

The section 7.2.2.2 of the report (PCCS-05-PT-ZP-9025-00004 Geomechanics Report, 2014), presents 2D simulations of thermo-elastic stresses applicable to the cold injection of CO_2 in the Goldeneye reservoir near the injection point. The study showed that the difference in major and minor principal stress was greatly reduced in the cooled region around the fracture owing to the large reduction in the major principal stress parallel to the fracture.

Considering the difference in temperature between the injected CO_2 and the reservoir temperature then the maximum injection pressure should not exceed 4860psia (33.5 MPa, 335bara) with no safety factor. Considering a safety factor of 90% then the maximum bottom hole injection pressure should not exceed 4370psia [301bara] unless a new risk assessment is performed.

9.2 Design Conditions - CITHP

The CITHP will depend on the reservoir pressure (or downhole pressure) and the fluid inside the tubing. Two extreme cases exist: CO_2 filling the well and CH4 filling the well.

The wells will be designed to accommodate water/CO_2/gas for corrosion purposes and wellhead pressures related to hydrocarbon gas filling the tubing.

9.2.1 CITHP for CO_2 and CH_4 filled tubing

For a CO_2 filled well, the CITHP is relatively low of approximately 50bara at reservoir pressures at the end of the 10 million tonnes injection of 3500psia [241bara]. See Figure 9-1 below.

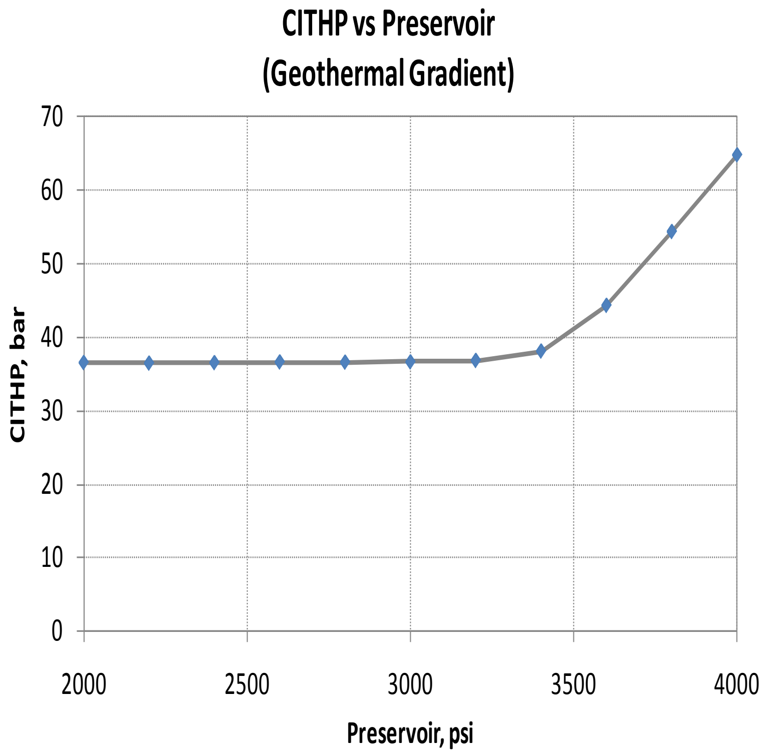
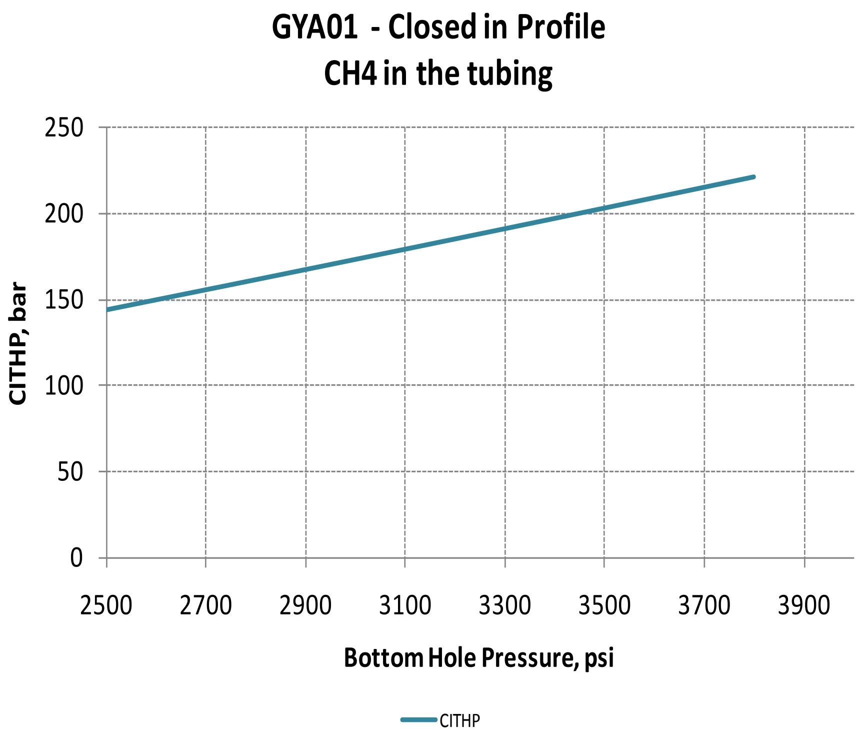


Figure 9-1: CITHP for a well filled with CO_2

In case that the well is full of hydrocarbon gas then the CITHP at the same 3500psia reservoir pressure would be in the order of 205bara (assuming methane filling the tubing), see Figure 9-2



below.

Figure 9-2: CITHP for a well with Methane in the tubing

9.2.2 Scenarios

The tubing will be left after the commissioning/workover operations with water/brine and probably a N_2 cushion in the top of the well. The reservoir currently has gas and water and the reservoir pressure is increasing with time even without CO_2 injection due to the aquifer strength. The reservoir pressure will increase faster with CO_2 injection.

CO_2 will be injected into the wells displacing initially the water/N_2 from the well. If CO_2 continues for long time in the same well then the expected fluid inside the well is CO_2 when the well is closed in.

However, if the well is left closed-in for a long time and because of the increase of reservoir pressure (by the aquifer or CO_2 injection in another well), fluid segregation in the reservoir (gas moving to the top of the reservoir) and a potential arrival of a hydrocarbon bank displaced by the CO_2 plume (injected into another well) then the CO_2 inside the tubing can be displaced to hydrocarbon. Under this scenario the wellhead pressure will increase to the hydrocarbon case.

The monitoring well will be left closed-in for a long time. It is likely in this well to have a scenario where the water left in the well after the workover is displaced by hydrocarbon gas considering the increase in reservoir pressure (with / without CO_2 injection), segregation of fluids in the tubing and the arrival of a hydrocarbon bank into the well before the CO_2 breakthrough. CO_2 breakthrough will take place in the monitoring well at around 10 Mt of injection, near the end of injection.

If the wells are filled with hydrocarbon gas then CO_2 cannot be injected in the wells due to the higher CITHP than the available CO_2 pressure.

9.3 Packer Fluid

The fluid left in the A annulus for Goldeneye Wells should have the following characteristics:

- Avoid/minimize Corrosion in tubing/production casing. Compatibility with tubing and casing.
- The rheological properties of the packer fluid should be stable during injection period. It should have a low freezing point to cope with the well transient condition and should be stable in terms of phase envelope.
- The fluid should be solid free.
- Have the ability to monitor the annuli pressure over time. Positive pressure at all times.

Alternatives are (i) base oil designed for low temperature with a Nitrogen cushion which manages the thermal expansion of the base oil or (ii) water based systems with freezing point depressor (e.g. methanol) or special brine or (iii) water based brine in the bottom of the well with N_2 cushion in the top, to manage thermal expansion.

Annular fluids will be selected during FEED.

9.4 Well abandonment

Abandonment concepts and their reasoning have been described in the document (PCCS-05-PT-ZW-7180-00001 Abandonment Concept for Injection Wells, 2014).

In summary:

- Permeable zones requiring abandonment:

Captain sandstone: Formation receiving the CO_2. It will contain hydrocarbon, water and CO_2. Hydrostatically pressured (~3500-3800 psia [~241-262bara]) or slightly depleted after CO_2 injection. The primary seal for the Captain reservoir is the Rodby shales/Hidra marl. These formations are impermeable, strong and about 500ft [152m] in vertical thickness. In Goldeneye, these formations are positioned right above the Captain reservoir.

Tertiary sandstones (Balmoral, Dornoch): water bearing, hydrostatically pressured. However, in case of CO_2 leakage into this formation then CO_2 will need to be considered for the abandonment. The Balmoral sandstone formation is contained by the Lista shales.

- Number of cement plugs

  Over-pressured permeable zones (both water and hydrocarbon bearing) and normally pressured permeable zones containing hydrocarbons require a minimum of two Permanent (abandonment) barriers between the permeable zone and seabed/surface.

  Normally pressured permeable zones containing water require one Permanent (abandonment) barrier between the permeable zone and seabed/surface.

- Cement

  The reference case for cement plugs is Portland cement. The type of cement to be used will be reviewed later and may include CO_2 resistant additives. Some alternatives to cement (like resins, etc.) may be considered as well. This will be influenced by the best practices and standards of the day at the time of abandoning.

- Geometry of cement plug

  Two options exist for the primary seal: rock to rock cement plug or internal and external with pipe.

  The reference case for cement plugs is Portland cement. The type of cement to be used will be reviewed later and may include CO_2 resistant additives. Some alternatives to cement (like resins, etc.) may be considered as well. This will be influenced by the best practices and standards of the day at the time of abandoning.

Different options exist for abandoning the injection wells. The reservoir abandonment will be selected close to the time of abandonment.

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A1.Drilling of new wells: CO_2 expansion in the tubing

New wells are not the reference case for the project. This section is included for completeness of the report.

A1.1.Reasons for considering new wells

The objective of a new well would be to avoid the limitations in terms of minimum rate or to overcome design issues in the existing wells created by low temperatures.

A1.1.1. Injection Flexibility and Temperature rating

The objective of a new well would be to avoid the limitations in terms of minimum rate. As a consequence, the well should be able to withstand to extreme low temperatures in the top part of the well (~2600ft [792.5m] in sub-zero temperatures, see Figure 4-6) during the injection time. This will bring new challenges to the well design in terms of temperature rating.

There is no point in drilling new wells and managing the CO_2 arrival rates to the platform using the selected friction concept as there are enough existing wells which can accommodate the arrival rates to the platform and it is cheaper to perform workovers compared to drilling new wells.

A.1.1.2. Leak scenarios

As mentioned in section 4.6, a partial loss of containment might occur with possibility of low temperatures. A metal temperature of -55°C is proposed to be used. Well Materials in contact with the CO_2 as the Xmas tree and top part of the tubing (above the SSSV) can be changed to be compatible with this low temperature during the workover. However, other elements as the casing hanger and the wellhead compact spool system which are rated to -18°C cannot practically be changed during the workover. However, these elements are not in contact with the CO_2.

The influence of a leak to atmospheric conditions will be calculated during early FEED in order to determine the extent of the lower temperature in the wellhead / Xmas tree system.

In case that the wellhead system temperature in a leak scenario is above the current rating of the system then no new wells are required (reference case). The consequence of having lower temperatures than the temperature wellhead system then new wells might be required.

Available information on well design from a CCS project in Canada and CO_2 EOR projects in onshore America do not consider the resultant low temperature in case of a well leak. For example in the Canadian project, the low temperature rating is related to the winter ambient temperatures (~-43°C minimum) and not the leak resultant temperature.

In a fully uncontrolled release scenario (blowout) (section 4.7) the recovery mechanism is related to bring the well back under control as the hazards generated during this scenario (cold CO_2, low visibility) would likely prevent access to the well. Even if attempts are being made to kill a well from surface, a relief well will also be drilled. Under this scenario, the well cannot be used again for injection or monitoring purposes.

A1.2.Well Design for New Wells

The low temperatures (-25°C) created by the expansion of the CO_2 during injection or to be able to handle uncontrolled CO_2 releases will create issues in terms of well design. The following aspects have been identified as the main well design considerations regarding new platform wells.

A1.2.1 Drilling

No changes are expected in the undepleted overburden in the case of drilling of new wells. Learning from the previous Goldeneye wells should be included.

The degree of depletion in the reservoir will depend on the time that the well is drilled. Drilling of the undepleted overburden with the depleted Captain needs to be properly managed to avoid well drilling issues and impairment to the formation.

The Rodby shale should ideally be isolated from any sand control devices to avoid high skin in the wells as observed in the existing platform wells. This needs to be evaluated with respect to the position of the casing points and well control.

In case of drilling deeper of the Captain D then reservoir pressure uncertainty should be considered in the drilling design. This will impact the selection of the lower completion.

A.1.2.2. Well Materials

A1.2.2.1 Carbon Steel

Normal CS ("LT0") is adequate down to 0°C. Any carbon steel tubular used in the top part of the well needs to be qualified/certified for extreme low temperatures. Adequate toughness would be required.

A1.2.2.2. Production Casing or Liner Material

Any production casing or liner material to be in contact with the CO_2 should be defined with a material compatible with CO_2, water and possibly O_2. This might relax the Oxygen specification in the project.

A1.2.2.3. Tubing and Lower Completion Material

The material of the tubing and the lower completion should be optimised considering the lifecycle of the project. For example, the tubing and the lower completion in contact with CO_2 can be changed to a material (e.g. 25Cr) where there is adequate management of low temperatures and CO_2 corrosion without the restriction of the limiting the oxygen content in the CO_2. Material selection in this type of wells can relax the specification of the O_2 in CO_2.

A1.2.3. Conductor and Casings

The conductor and the surface casing can be made of Carbon Steel with adequate toughness in the top of the well to resist the continuous low temperature.

Depths for setting the conductor and the casing will be similar to the current wells.

The production casing can be made of carbon steel above the packer and CRA below the packer to provide extra corrosion protection. Ideally the production casing should be set immediately above the reservoir to avoid impairment issues related to the lower completion if sand control is required. It can also be considered to use a 13Cr production casing above the packer to avoid corrosion of the production casing in the unlikely case of a tubing leak and a water based completion fluid.

A1.2.4. Cement

The primary cement sheath of the production casing is a barrier to contain the CO_2 downhole in the well. Portland cement (installed in the existing wells) is suited for CO_2 conditions. Choice between the use of Portland cement and CO_2 resistant cement should be evaluated during considering the advantages, disadvantages of both system and the operational experience worldwide.

A1.2.5. Surface Trees and Wellheads

The new Goldeneye Xmas tree and wellhead should be suited to CO_2 injection for the specified steady state operating parameters. The current Xmas tree class "U" is qualified for temperatures above -18°C. The lowest qualified temperature for Xmas trees is -60°C (class "K").

A1.2.6. Upper Completion

All completion equipment should have metallurgy compatible with CO_2 and the low temperatures in the top of the well; it should have working pressures in excess of the expected final well pressures.

A preliminary evaluation indicated that 5.5" [140mm] or 7" [178mm] tubing size can be used for this application. By installing this large tubing and being able to manage low temperatures in the new wells will increase the flexibility in terms of managing arrival rates to the platform. The wells would be able to take daily variations of the capture plant CO_2 profile.

The Goldeneye SSSV is currently set at ~2,500 ft [762m]. The current depth of the valve was selected according to the hydrate deposition curve in the hydrocarbon phase, a situation which cannot be disregarded for CO_2 injection, as the presence of hydrocarbon in the well is likely (wells will be completed initially in the hydrocarbon leg and a hydrocarbon bank displaced by the CO_2 can be formed).

The minimum installation depth for the SSSV will also depend on the depth where the CO_2 is in dense phase under injection conditions (avoid important cooling by reduction pressure changes). Also, the temperature rating of the valve should be considered. The temperature rating of the SSSV is -7°C. Under two phase injection this temperature is reached at a depth of around 640m [2100ft] at 2500psia [172.4bara] reservoir pressure.

In the new wells the packer should ideally be placed across the Rodby formation and in CRA in casing (at least below the packer). This will provide extra protection for CO_2 corrosion.

The completion can feature a permanent temperature and pressure monitoring gauges. There will also be a distributed temperature sensor strapped outside of the tubing - a fibre optic system taking temperatures every one metre in the well. In the event of a tubing leak, the distributed temperature readings would facilitate the location of the leak.

A.1.2.7. Lower Completion

Drilling new platform wells will increase the degree of freedom with respect to the completion strategy across the sand face. There are two different types: cased/perforated and sand control. During the previous phase of the project (Longannet) it was recommended to install sand control even in the new wells, however, this will require further evaluation/confirmation.

A sand control completion is currently the preferred option for new wells based on the Longannet study. Current wells are gravel packed using the alternate path systems. Gravel packing in depleted reservoir might be a challenge. The option to install Stand Alone Screens (SAS) is open.

Another option is for case and perforate completion. A rat hole is required and operational control is required during the closing-in operation of the well (to avoid pressure surges in the formation which might exacerbate the sand production). Special sand production studies will be required to ensure the long term integrity of this completion.

As CO_2 will be injected into the well it is imperative not to block or damage the lower completion. Plugging of the formation/lower completion can be avoided by filtration of the injected CO_2. This is considered feasible for the platform option.

A1.2.8 Packer fluid

With the expected low temperatures, there is no option to use simple water based fluids due to the higher freezing point of the brines. Alternatives are (i) base oil designed for low temperature with a Nitrogen cushion which manages the thermal expansion of the base oil or (ii) water based systems with freezing point depressor (e.g. methanol) or (iii) water based brine in the bottom of the well with N_2 cushion in the top, to manage thermal expansion.

A1.2.9. B-C annulus fluids

Any fluid left in these annuli should be resistant to low temperatures and it should be able to manage the thermal expansion of the thermal cycles. Potentially, a N_2 cushion can be placed depending on the top of the cement achieved during the casing cementations.

C- annulus can be left open as in the existing Goldeneye wells.

A1.2.10 Currently unknown elements

The operation of the well at sub-zero temperatures during the injection time will bring some challenges, which have not been solved currently as:

- Freezing of sections adjacent to the well.
- Interstitial water in the shallow formations below the seabed can be frozen during the injection time; however during the closed-in period, this water will melt. It is unknown if these operational cycles will cause problem to the well integrity.
- For platform wells, the frozen riser might have an impact on the resultant temperature of other wells.

A1.3. Comparison of existing Workover wells versus New Platform wells

The main benefit in drilling this type of new wells is the elimination of the required minimum rate, as the wells by design should be capable of taking low temperatures. This will increase the flexibility in terms of managing arrival rates to the platform. The wells would be able to take daily variations of the capture plant CO_2 profile. Operator intervention would also be minimised.

Currently there is not a justification to drill new wells. Well aspects related to low temperature in the existing wells during uncontrolled CO_2 releases need to be evaluated to validate this decision.

Table A0-1: Workover with the current friction concept and drilling new wells. Advantages and disadvantages.

	Existing Platform Wells Workover with single tapered tubing	New Platform Wells (for two phase injectors)
General	(+) Green project. Re-use of the existing infrastructure. (+) Reduced uncertainty. Wells completed in the top part of the Captain D.	(-) More penetrations in the overburden. Increases the risk of a leak. (+) Might increase flexibility in injection point. (-) Low temperature in the top of the well (down to -2600ft at low reservoir pressure) and the Xmas tree area.

Well Design / Construction	(+) High level of maturity. Investigated for the Longannet - Goldeneye CCS case. Minor issues pending (e.g. A-annulus fluid). (-) Requires special Jack-Up rig Design based on friction form small diameter tubing.	(-) Low level of maturity. Identified fundamental well issues which require further work. (+) Extra well protection by installing CRA in the casing below the packer (-) Requires special jack-up rig
Integrity	(-) limitations of -18°C in the wellhead system (+) Xmas tree can be changed to -60°C	(+) wellhead / Xmas tree can be installed to -60°C
Injectivity	(+) Known hydrocarbon production properties. Filtration required to ensure long term injectivity	(-) More uncertainty in injectivity. High skin might be expected due to drilling in depleted reservoir.
MMV / WRM	(+) Easy access to the wells	(+) Easy access to the wells. (+) Ability to design the well for the instrumentation to be closer to the formation than existing wells.
Well Operations	(-) Any injector well will have a minimum rate dictated by the CO_2 phase management. (+) Management of CO_2 rate optimized with the number of wells	(+) No minimum rate. Variable flow might be accommodated in a single well.
Well Requirement	5 wells to be worked over. (2 required for injection, 1 back up, 1 monitoring well and 1 conversion to injector	Requires the abandonment of the existing wells + the cost of drilling at least 2 wells.

10 Glossary of terms

Term	Definition
"	Inches [1" = 25.4mm]
13Cr	13 percent chrome content metallurgy
1D, 2D, 3D	One, two, three Dimensional
'A' annulus	Annulus between the production tubing and production casing string
Annuli	The space between adjacent strings of tubing or casing
'B' annulus	Annulus between the production casing and intermediate casing string
bara	Standard measure of pressure [1bara = 100,000Pa]
Barrier	Barriers prevent of mitigate the probability of each threat or prevent, limit the extent of, or provide immediate recovery from the Consequences
Base oil	Oil with carcinogenic elements removed
BHP	Bottom Hole Pressure
BHP&T	Bottom Hole Pressure and Temperature
Cap rock	The shale layers above a reservoir that provide geological isolation to upward migration and provide the primary seal
CBIL	Circumferential Borehole Imaging Log
CBL	Cement Bond Logging
CCP	Carbon Capture Plant
CCS	Carbon, Capture and Storage
CDT	Conductivity Depth and Temperature
Cement squeeze	Injection of cement to isolate a leak in the cement behind casing
CITHP	Closed in Tubing Head Pressure
CO_2	Carbon Dioxide
Completion	The conduit for production or injection between the surface facilities and the reservoir. The upper completion comprises the tubing and packer, etc. The reservoir completion is the screens, etc., across the reservoir interval.
CoP	Cessation of Production
CRA	Corrosion Resistant Alloys
CTU	Coil Tubing Unit
DAS	Distributed Acoustic Sensing
DECC	Department of Energy and Climate Change
DIANA	Software package from TNO that solves, with the aid of FEM, problems relating to design and assessment activities in concrete, steel, soil, rock and soil-structure.
DP	Differential Pressure

DTS	Distributed Temperature System
ECP	External Casing Packer
EOR	Enhanced Oil Recovery
EU	European Union
FEED	Front End Engineering Design Define phase
FEM	Finite Element Modelling
FFM	Full Field Model
FFSM	Full Field Simulation Model
FIV	Formation Isolation Valve
FWHP	Flowing WellHead Pressure
FWHT	Flowing WellHead Temperature
FWL	Free Water Level
GPS	Global Positioning System
GR	Gamma Ray
Hazard	The potential to cause harm, including ill health and injury, damage to property, products or the environment; production losses or increased liabilities. In this report: buoyant CO_2
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability Study
HSE	Health, Safety and Environment
HSSE	Health, Safety, Security, and Environment
ID	Inside Diameter
ISE	Inflatable Setting Element
JT	Joule-Thomson effect
KNMI	The Royal Netherlands Meteorological Institute
Leakage	Migrated CO_2 out of the containment that leaks into the biosphere (shallow subsurface and atmosphere). In contrast to seepage, leakage involves medium fluxes and medium concentrations
Leakage scenario	Group of threats that form cause-consequence relations leading to a certain route of migration and eventually leakage into the biosphere
LOP	Leak-off pressure
LOT	Leak-off Test
LT	Limit Test
LTMG	Long Term Memory Gauge
LWD	Logging Whilst Drilling
m	Meters

MBES	Multi Bean Echo Sounder
Mcf	Thousand cubic feet at reservoir conditions
MEG	Mono Ethyl Glycol
MFP	Manifold Pressure
MFT	Manifold Temperature
Migration	Escaped CO_2 out of the containment into the subsurface where it moves or trapped in other layers
mm	Millimeters
MMscfd	Million Standard Cubit Cubic Feet
MMV	Measurement, Monitoring and Verification
MoRes	Shell proprietary software used for simulating fluid flow in a reservoir
Mscf	Thousand cubic feet at standard conditions
NUI	Normally Unattended Installation
OD	Outside Diameter
Open shoe	An annulus that is open to a formation
OWC	Oil Water Contact
Packer	A device that both anchors and seals the tubing to the production casing. The term production packer is still used even when the well is in injection mode
PBR	Polished Bore Receptacle
PDG	Permanent downhole gauge
PEC	Pulsed Eddy Currency
pH	measure of the acidity or basicity of an aqueous solution
Production casing	The casing providing the secondary wellbore barrier during production or injection (valid term even in injection mode)
psia	Pounds per square inch [1psia = 0.06895bara]
PVT	Pressure, Volume, Temperature
PWRI-frac	Shell proprietary software used for modelling the effect of fluid injection on fracture development and growth
Relief well	A well constructedwell-constructed specifically to intersect the wellbore or reservoir of a blowing out well
Risk management	Risk management is the human activity, which integrates recognition of risk, risk assessment, developing strategies to manage it, and mitigation of risk using managerial resources
RST	Reservoir Saturation Tool
RTCI	Real Time Compact Imager
S13Cr	Super 13 percent chrome content metallurgy

Seepage	Migrated CO_2 out of the containment that seeps into the biosphere (shallow subsurface and atmosphere). In contrast to leakage, seepage involves low fluxes and low concentrations
SEM	Scanning Electron Microscope
Sh	Minimum Horizontal Stress
SITs	Non-flow wetted tests
SRM	Static Reservoir Model
SSSV	SubSurface Safety Valve
Straddle	A device comprising two packers and tubing designed to isolate leaking tubing or casing
TDS	Total Dissolved Solids
Threat	Means by which a hazard can be released and thus cause the top event
TNO	Netherlands organization for applied scientific research Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek
TOC	Top of Cement
Top Event	Incident that occurs when a hazard is realized, or the release of the hazard. The Top Event is typically some type of loss of control or release of energy. If this event can be prevented there can be no effect or consequence from the hazard
TVD	True Vertical Depth
TVDss	True Vertical Depth sub-sea
UCS	Unconfined Compressive Strength
UGS	Underground Gas Storage
UKCS	United Kingdom Continental Shelf
Under ream	To mill out a section of casing / cement by the use of an expandable milling bit
USIT	Ultrasonic Imaging Tool
VIT	Vacuum Insulated Tubing
VOI	Value of Information
WFS	Well Functional Specification
WITs	Well Integrity Tests
XLOT	Extended Leak Off Test

11 Glossary of Unit Conversions

For the provision of the SI metric conversion factor as applicable to all imperial units in the Key Knowledge Deliverable.

Table 11-1: Unit Conversion Table

Function	Unit - Imperial to SI Metric conversion Factor
Length	1 Foot = 0.3048m Metres 1 Inch = 2.54cm Centimetres 1 Inch = 25.4mm millimetres
Pressure	1 Psia = 0.0690 Bara
Temperature	1°F Fahrenheit = -17.22°C Centigrade
Weight	1lb Pound = 0.45kg Kilogram